Before the
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

In the Matter of	)	
	)	
ExxonMobil Pipeline Company	)	CPF No. 4-2013-5027
Pegasus Pipeline incident	)	Notice of Probable Violation
(March 29, 2013), Mayflower, Arkansas	)	

RESPONDENT'S PRE-HEARING BRIEF

I. INTRODUCTION

On March 29, 2013, the Pegasus Pipeline, a 20" diameter pipe carrying crude oil ruptured near Mayflower, Arkansas. The pipeline is owned by Mobil Pipe Line Company, and operated by the ExxonMobil Pipeline Company (EMPCo or the Company). The pipeline was constructed in 1947-1948 and maintained under regulations promulgated by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency). The Company conducted hydrostatic pressure tests of the line at the time of construction, in 1969, 1991 and again in 2005-2006. The Company also conducted in-line inspections (ILI) of the pipe multiple times, from 1999 to 2001, again in 2010, and again from 2012 to 2013. Hydrotests and ILI are conducted to detect anomalies that could lead to failure if not remediated, but no such anomaly was ever found or reported at the point of the Mayflower rupture prior to the incident.

PHMSA issued a Notice of Probable Violation, Proposed Penalty and Proposed Compliance Order (collectively, the NOPV) to EMPCo on November 6, 2013. The NOPV set forth nine alleged violations of the Agency's integrity management program (IMP) rules, and proposed a civil penalty in excess of $2.6 million dollars and a broad compliance order. The Company contested the allegations and requested an administrative hearing on the NOPV.

The federal Pipeline Safety Act (PSA) and PHMSA's regulations implementing that statute establish a set of performance-based regulations that require pipeline operators to create their own written programs, specific to the pipeline at issue. Under the IMP rules, operators are required to prepare a written IMP plan, create a Baseline Assessment Plan (BAP), establish a schedule for hydrotest and/or ILI assessment, and, where appropriate, develop risk reduction or remediation strategies. EMPCo fully complied with the IMP rules for this line. In fact, the Company conducted more inspections of the line and implemented more risk reduction measures than are required by the regulations.

The PSA does not create a strict liability scheme, meaning that the occurrence of an incident does not automatically give rise to a violation of PHMSA regulations. In this case, PHMSA has alleged violations as if strict liability did apply; the NOPV presumes violations simply because an incident occurred. The PSA and its implementing regulations make clear that such an approach is not consistent with the applicable law. Pipeline operators, and the Agency, are expected to continually improve IMP programs as new information and new technology become available, to find and correct violations when they occur, and also to learn from incidents even where no violations exist, in order to reduce the likelihood of recurrence.

As the evidence will show, the Company complied with all applicable regulations in this instance. The anomaly that caused the Mayflower incident was not detected prior to the incident using recognized industry best practices. Accidents can occur even when an operator is in full compliance with applicable law. The PSA and its regulations acknowledge that fact, but the NOPV ignores it.

This challenge to the NOPV is not about monetary fines. The Company has already paid many millions of dollars in response to the Mayflower incident. This challenge is about the proper interpretation of the PSA, and ultimately about the proper focus in learning from an incident and working to improve pipeline integrity and public safety.

The Agency should withdraw or revise the NOPV as issued.

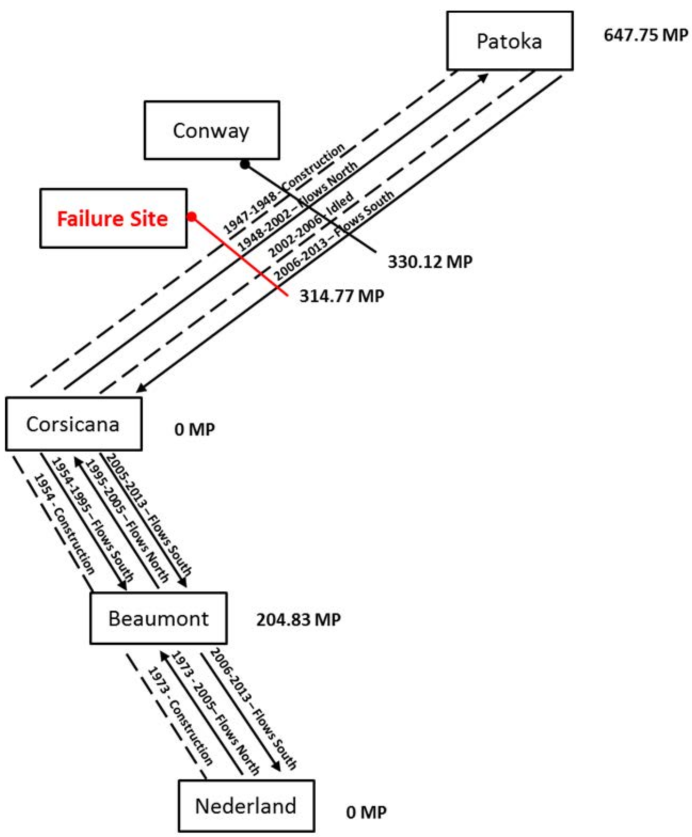
II. BACKGROUND

A. The Pegasus Pipeline System and the Mayflower Incident

The Pegasus Pipeline System consists of 859 miles of predominately 20” pipeline that transports Canadian heavy crude oil originating from Patoka, Illinois to Nederland, Texas, at which point the product is provided to Gulf Coast refineries and export marine facilities. The entire line was shut down in 2002 for market reasons, and was then reversed and restarted in 2005-2006. The system has a capacity of approximately 90,000 barrels per day and was operated at a MOP of 820 psi that was established through a 2006 hydrotest.

The system is comprised of three distinct pipeline segments that were constructed separately, with different metallurgy, manufacturer, and/or manufacturing methods, and that have been subject to different operating histories over the years. The segment at issue in this NOPV runs from Patoka, Illinois to Corsicana, Texas and was constructed in 1947-1948 from predominantly Youngstown 20” X-42/electric resistance weld (ERW) pipe, as well as some seamless pipe. *See Figure 1: Pegasus Pipeline System.*

Figure 1: Pegasus Pipeline System



On March 29, 2013, at 2:37 p.m. Central Standard Time (CST), a drop in pressure was detected in the Conway to Corsicana line segment by EMPCo’s Operations Control Center in Houston, Texas. Following receipt of a low pressure alarm (32 psig) and a pressure rate of change alarm (negative drop of 668 psig), the OCC controller began initiation of a full safe shutdown of the pipeline, which included a carefully staged shutdown of all pumps along the entire length of the

pipeline and full isolation of the section of the pipeline where the release was located by closing mainline valves upstream and downstream of the rupture site. As a result, EMPCo detected the potential release, confirmed it was an actual release, and shutdown and completely isolated the affected segment within 16 minutes of the rupture.

The pressure drop resulted from a rupture of the pipeline at Milepost 314.77, causing a release of crude oil near Mayflower, Arkansas. At the time of failure, the pressure at the release site was estimated to be approximately 703 psi (below the release site MOP of 863 psi). EMPCo reported the release to the National Response Center on March 29, 2013, at approximately 3 p.m. CST (NRC Report No. 1042466), estimating that between 3,500-5,000 barrels of crude oil had been released. On April 8, 2013, EMPCo revised that estimate to 5,000 barrels.

EMPCo immediately initiated response efforts, in coordination with PHMSA, U.S. EPA, local police and other State and local agencies. The release occurred in a residential neighborhood and twenty-two homes were evacuated as part of the Company's response efforts. No injuries, fatalities or fires occurred. While the oil flowed into storm drains leading to nearby Lake Conway, a local fishing spot, no oil is believed to have reached the main body of the lake. To date, the Company has expended more than $75 million in response related costs. The line has not yet been put back in service.

B. <u>PHMSA Initial Administrative Action</u>

PHMSA issued a Corrective Action Order (CAO) to EMPCo on April 2, 2013, just three days after the release occurred. The CAO imposed four major corrective actions on the entire Pegasus Pipeline: metallurgical testing, preparation of a remedial work plan and a Restart Plan, and a pressure restriction. EMPCo requested a Hearing on the CAO, seeking to clarify or modify the Order with respect to the following: (1) the restart pressure restriction at the failure location; (2) the extent of the system subject to the CAO and the hazardous facility determination; and (3) restart pressure restrictions at other stations along the pipeline. Following the Hearing on May 2, 2013, PHMSA issued a Final Order on May 10, 2013, agreeing to amend the CAO to address the pressure issues and acknowledging that the scope of the CAO could be limited in the future depending on the results of further investigation.

C. <u>Root Cause Failure Analysis and Re-Start Plan</u>

The Root Cause Failure Analysis (RCFA) that EMPCo submitted to PHMSA on April 15, 2014, concluded that the failure was caused by original manufacturing defects, namely hook cracks along material imperfections in steel on the long seam. *Exhibit 56, EMPCo Pegasus RCFA Final Report, p. 2 (Mar. 26, 2014)*. The initial defects grew in service, over time, to critical flaw size, which resulted in the rupture. Metallurgical testing conducted by HurstLab concluded that the failure occurred:

> because of the reduction of the wall thickness in the upset zone of the Electric Resistance Weld (ERW) seam caused by the presence of manufacturing defects, namely the upturned bands of brittle martensite, combined with localized stress concentrations at the tips of the hook cracks, low fracture toughness of the material in the upset/HAZ, excessive residual stresses in the pipe from the initial forming and seam and girth welding processes, and the internal pressure creating hoop stresses.

Exhibit 55, Hurst Metallurgical Report No. 64961, p. 31 (rev. July 9, 2013). With respect to other contributing or likely contributing factors, EMPCo and industry expert John Kiefner who provided input on the RCFA identified atypical pipe properties that contributed to accelerating the propagation of cracks and the failure (*e.g.*, very high tensile strength, local high hardness, high carbon and manganese content, brittle fracture mode, residual stresses). *Exhibit 56, Appendix 3 to EMPCo Pegasus RCFA Final Report prepared by Kiefner & Associates*; *see also Exhibit 1, Kiefner Affidavit* ¶¶ 16-17, 24 (noting that the Pegasus Pipeline "exhibited highly unusual chemical and mechanical properties," "the characteristics of the pipe at the particular point of failure were unique," and that "the anomaly that caused the Pegasus incident was not capable of reliable detection give that it exhibited atypical characteristics not frequently seen before in the industry").

As required by the CAO, EMPCo continues to work with PHMSA to develop approved Re-Start Plans (RSP) for the pipeline.[1] A RSP for the portion of the line between Corsicana and Nederland, Texas was submitted to the Agency on January 31, 2014. The RSP was approved by the Agency on March 31, 2014 and plans are underway to initiate restart. The Company continues to finalize its RSP plan for the Patoka to Corsicana portion of the line before submitting it to PHMSA.

D. <u>Issuance of NOPV, Proposed Penalty and Compliance Order by PHMSA</u>

PHMSA issued the NOPV to EMPCo on November 6, 2013, including nine (9) Items of alleged violation, proposing more than $2.6 million in civil penalties and proposing a Compliance Order. Eight of the nine alleged violations cite to PHMSA's IMP regulations at 49 C.F.R. Part 195.452. One of the alleged violations invokes Part 195.402 (concerning Operation & Maintenance Manual requirements) but that Item also directly relates to IMP. All of the alleged violations are associated with a proposed penalty. Five (5) of the alleged violations (Items 1, 2, 5, 6 and 8) are related to the Proposed Compliance Order (PCO). EMPCo timely requested a hearing on December 6, 2013, pursuant to PHMSA regulations at 49 C.F.R. Part 190. The Hearing is scheduled for June 11, 2014.[2]

[1] Additionally, in compliance with the CAO, the Company submitted Remedial Work Plans (RWP) to PHMSA for both the Corsicana to Nederland, Texas portion of the pipeline and the Patoka, Illinois to Corsicana, Texas portion. EMPCo continues to work with the Agency to finalize the RWPs.

[2] Following the issuance of the NOPV, EMPCo requested and received on November 21, 2013, a copy of PHMSA's "Pipeline Safety Violation Report"(PSVR) (dated Nov. 6, 2013), and a copy of PHMSA's "Mayflower Failure Investigation Report" (dated Oct. 23, 2013). Neither of these documents are referred to or incorporated into the Agency's NOPV, but they provide information relied upon by PHMSA in preparing its claims in the NOPV. The documents, both of which are lengthy, contain incorrect factual information and unsupported legal conclusions that go beyond the allegations set forth in the NOPV. To the extent any such information or conclusions are relevant and material to the claims presented in the NOPV, EMPCo addresses it in its Request for Hearing pleadings (including this Brief). The Company is not addressing the entirety of the PSVR or Accident Report in this proceeding, however, and the Company denies any and all factual or legal conclusions contained in those documents.

III. APPLICABLE LAW

A. There is No Strict Liability under the PSA

It is evident that the government believes that simply *because* an incident occurred in this matter, then EMPCo must have violated the Part 195 regulations. The legal concept of strict liability supports such an approach, but it is not available here. Where strict liability does apply, an entity may be liable solely because of the occurrence of an event, without consideration of fault or cause.[3] The federal PSA has no such strict liability provision. There is nothing in the statute or PHMSA regulations implementing the statute that establishes liability for a pipeline incident without fault.

The Agency's regulations instead establish a series of performance based standards, which often incorporate various technical standards and methods. This performance based scheme is intended to provide operators with flexibility to select the most effective processes and technologies based on their specific pipeline characteristics.[4] Pipeline operators are required to follow the procedures established in this regulatory framework, and document all relevant considerations and actions taken.

Although many pipeline accidents are associated with underlying violations of PHMSA regulations (*e.g.*, operator error, failure to maintain specified records, insufficient cathodic protection, etc.), some incidents occur despite an operator's compliance with all applicable regulations. *See Exhibit 2, Muhlbauer Affidavit* ¶ 13 (noting that "[d]ue to the probabilistic nature of such scenarios, incidents can occur despite significant efforts to prevent them"). This is one such incident. Unfortunately, whether influenced by media attention or political pressure, agencies are sometimes inclined to presume violations simply because an incident occurred. The law does not support such an approach. The Agency must prove, as a matter of law, that a violation of its regulations occurred to support each of the nine items in the NOPV in this case.

B. Overview of Integrity Management Rules

When promulgating the integrity management regulations at 49 C.F.R. Part 195.452, PHMSA increased its emphasis on performance based risk management regulations. More so than any other regulations under Part 195, the integrity management rules are process oriented and allow operators a high degree of flexibility to adapt their programs and plans to fit particular circumstances. *Final Rule, 65 Fed. Reg. 75378, 75382 (Dec. 1, 2000)* ("Performance based language will best achieve effective integrity management programs that are sufficiently flexible

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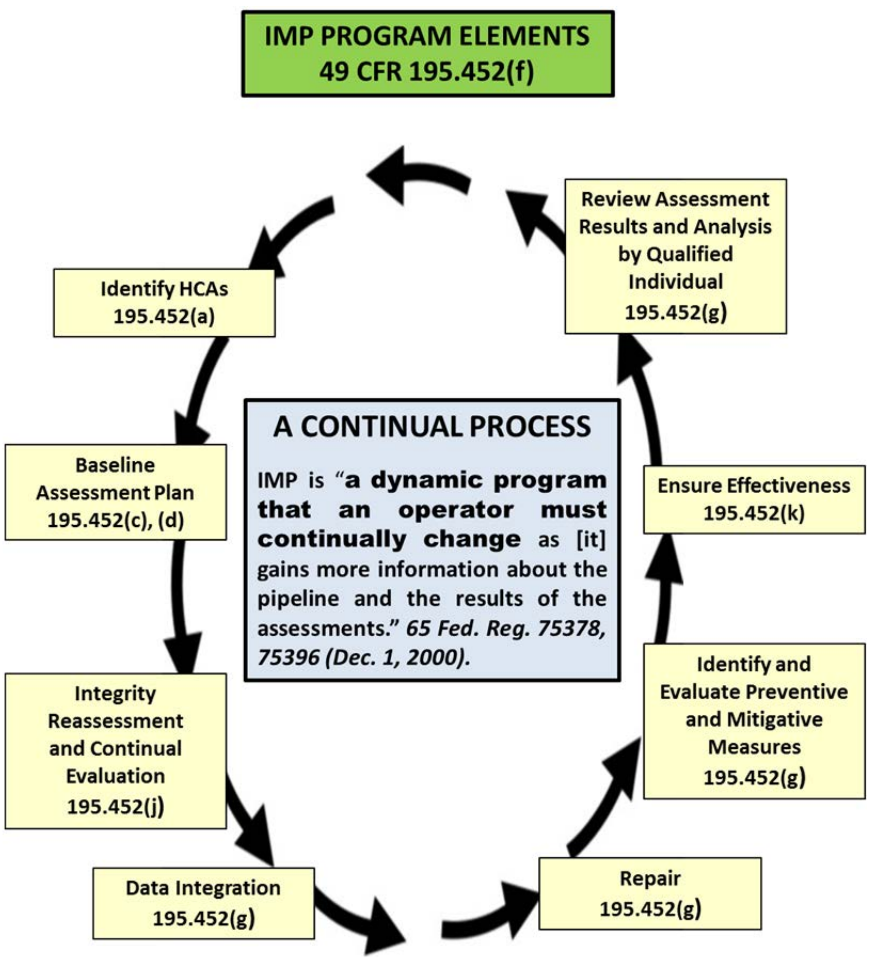
[3] An example of such a provision is found at Section 301 of the federal Clean Water Act (known as 'the discharge prohibition'), where any unpermitted release of oil to waters of the U.S. creates liability regardless of how or why the release occurred. *33 U.S.C. §§ 1311(a), as implemented through 33 U.S.C. §1321(b)(6)(A)* (authorizing assessment of administrative penalties to any "owner, operator, or person in charge" of a vessel, onshore or offshore facility from which oil is discharged); *1321(f)* (creating liability for removal costs up to finite amounts for such owners or operators and providing for increased liability where the government can show willful negligence or willful misconduct).

[4] In promulgating the original 1969 liquid pipeline regulations, which were the blueprint for the current regulations at Part 195, DOT's Hazardous Materials Regulations Board emphasized performance over prescriptive standards for the purpose of encouraging industry innovation and technological improvements. *See e.g., Final Rule, 34 Fed. Reg. 15473, 15474 (Oct. 4, 1969).*

to reflect pipeline specific conditions and risks. Performance based standards allow an operator to select the most effective processes and technologies as they become available.").

Under these rules, which first became effective in 2001, operators were required to develop a written IMP plan that included the following: (1) identification of pipelines that could affect sensitive areas called high consequence areas (HCAs); (2) a baseline assessment plan (BAP) for initial assessments of those lines; (3) procedures for the integration of all available information about pipeline integrity and the consequences of a failure; (4) prompt action to address issues identified by the assessment and prioritization of repairs; (5) reassessment at least every five years; (6) continual evaluation to include additional preventive and mitigative measures as appropriate; (7) methods to measure effectiveness; and (8) a process for review of the assessment results by a qualified individual. *49 C.F.R. Part 195.452(f); see Figure 2: IMP Program Elements.*

Figure 2: IMP Program Elements, 49 CFR Part 195.452(f)



While the rule prescribes which program components are required, its performance based elements allow operators discretion in how to implement these components. For that reason, PHMSA anticipated that this would be an evolving "dynamic" iterative process for both operators and the industry, and the agency continues to emphasize that point. *Final Rule, 65 Fed. Reg. 75378, 75386 (Dec. 1, 2000); see also PHMSA Advisory, 79 Fed. Reg. 25900, 25993*

(May 6, 2014) ("Continual improvement of IM programs (including improvements in the analytical processes involved in analyzing assessment results, identifying threats, responding to risks, the application and implementation of assessments and the development of preventative and mitigative measures) is a key aspect and critical objective of an effective IM program."). As recent statistics confirm, the performance-based integrity management rules have been successful in improving pipeline safety. Since the liquid IM regulations became effective in 2001, liquid pipeline incidents have decreased by 62%, the amount released by liquid pipelines has decreased by 47%, and liquid incidents that resulted from material defects, seam and weld failures decreased 31%. *Annual Liquid Pipeline Safety Performance Report & Strategic Plan,* prepared by AOPL and API, p. 15 (2013).

C. <u>Threat Identification and Risk Assessment under IMP</u>

A primary component of IMP is the operator's threat identification and risk assessment process which informs both the integrity assessment schedule and its method under certain circumstances. *49 C.F.R. Parts 195.452(e); 195.452(j)(5).* The Agency requires operators to evaluate numerous risk factors for each pipeline segment, including the results of prior assessments, manufacturing information and seam type, among other factors. *49 C.F.R. Part 195.452(e).* Based upon the results of that analysis, an operator must prioritize its segments for reassessment on a five year interval. *49 C.F.R. Part 195.452(j)(3).* Consistent with the intent of the IMP regulations, operators are required to consider all of the regulatory risk factors in developing their assessment schedule, but they have discretion in determining the weight and risk score given to each factor and prioritization for a particular pipeline system. *See e.g., In re Magellan Midstream Partners, CPF No 4-2006-5020 (July 9, 2009).*

The IMP rules set forth three assessment methods available to operators: (1) inline inspection or ILI; (2) hydrostatic pressure testing; and (3) external corrosion direct assessment. *49 C.F.R. 195.452(j)(5).* For low frequency ERW (LF-ERW) or lap welded pipe <u>*that is susceptible to longitudinal seam failure*</u>, the assessment method "must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies." *Id.* PHMSA guidance clarifies that these methods include an ILI device capable of detecting seam flaws, metal loss corrosion, and deformation anomalies, or a hydrostatic test. *PHMSA Hazardous Liquid FAQ 6.10*. In addition, PHMSA guidance clarifies that evaluation of seam susceptibility "can involve a variety of factors such as original pipe purchase specifications, incident history, operating pressure, prior pressure testing, pressure cycling, etc." *PHMSA Hazardous Liquid FAQ 6.11(a).* PHMSA guidance also notes that a process should be in place to reevaluate this determination on an appropriate interval if any factors have the potential to change. *Id.* Beyond this, PHMSA has not promulgated any additional requirements or guidance associated with integrity management requirements for LF-ERW pipe.

An Agency-commissioned report was released in 2004 to address how an operator should assess whether LF-ERW pipe is susceptible to seam failure. *See Michael Baker and John Kiefner, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation (2004) (Baker/Kiefner Report).* This report was largely based on a 2002 report issued by Kiefner, entitled *Dealing with Low Frequency Welded and Flash Welded Pipe with Respect to HCA Related Integrity Assessments (2002).* While the evaluative process described in these reports is not incorporated into the regulations, it has been endorsed by the Agency through subsequent enforcement and referenced

in the Agency's enforcement manual.[5] Specifically, the process considers pipe and seam characteristics, in service and hydrostatic test failures, the cause of those failures, operating stress level, fracture toughness, fatigue crack growth rate characteristics and the nature of operational pressure cycles on the pipeline. This data is then applied to determine whether a given segment of LF-ERW pipe is susceptible to seam failure. *Id. at p. 18 (Figure 4.1.);*[6] *see also Exhibit 3, Baker/Kiefner Report Figure 4.1.*

For the reasons noted above, and contrary to PHMSA's assertions in the NOPV and Pipeline Safety Violation Report (PSVR), all LF-ERW pipe is *not* presumptively susceptible to seam failure. PHMSA law and guidance requires consideration of seam failure susceptibility, but it does not require a presumptive conclusion of susceptibility where the pipeline has been subjected to a hydrostatic test and an engineering analysis indicates that there is no evidence of pressure cycle fatigue, preferential seam corrosion, or other time dependent defects.

D. Discovery, Mitigation and Risk Reduction

After carrying out an integrity assessment, PHMSA regulations require that operators validate the results of an integrity assessment, account for ILI tool tolerances, and integrate all available data regarding the pipeline. *49 C.F.R. Part 195.452(g); PHMSA Hazardous Liquid IMP FAQ 7.19* ("tool tolerance should be considered as part of the data integration process" as well as prior excavations, digs, and inspections). Factoring in that analysis, operators "discover" integrity conditions when they have adequate information about the condition to determine whether an anomaly exceeds the criteria established in the IMP regulations. *49 C.F.R. Part 195.452(h)(2).*[7] This must occur promptly, but no later than 180 days after an assessment unless that period is impracticable, allowing for flexibility because discovery varies depending on the circumstances. *Final Rule, 65 Fed. Reg. 75378, 75384 (Dec. 1, 2000)* (noting that discovery may occur when an operator receives the preliminary ILI report, gathers and integrates information from other inspections or periodic evaluations, excavates the anomaly or receives the final internal inspection report); *see also PHMSA Hazardous Liquid IM FAQ 7.3*.

Once operators declare discovery, they must timely remediate and repair integrity conditions that exceed regulatory criteria based on a prioritized schedule. *49 C.F.R. Part 195.452(h)(3)-(4).* While some conditions require immediate repair, others must be scheduled within 60 days of

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[5] *In re Kinder Morgan Energy Partners, CPF No. 1-2004-5004 (June 26, 2006)* (noting that Kiefner's methodology is an example of an acceptable means of performing a seam failure susceptibility analysis); *see also PHMSA Hazardous Liquid IM Enforcement Guidance p. 131 (Sept. 17, 2013).*

[6] Notably the Baker/Kiefner Report explains that Figure 4.1 "represents a decision tree that allows one, by supplying appropriate data on a given segment, to determine if a seam-integrity assessment is required *based on the federal pipeline integrity management regulations*" and that "baseline assessment in the form of a hydrostatic test demonstrates a level of serviceability consistent with the test-pressure to operating pressure ratio the operator selects. Additional information may be derived from the examination of test leaks or breaks if any occur. Remaining life after the test can be assessed from the standpoint of pressure-cycle induced fatigue. *The results of the test are expected to provide sufficient information for the operator to decide whether or not the pipeline is susceptible to seam failure in the context of the federal regulations pertaining to pipeline integrity management* (49 C.F.R. 195.452)." *Baker/Kiefner Report*, pp. 16-17 footnote 3 *(emphasis added).*

[7] PHMSA guidance clarifies that where tool run data is suspect and an entire rerun is performed, the evaluation will be expected within 180 days of the successful tool run. *PHMSA Hazardous Liquid IMP FAQ 4.13*.

discovery, 180 days, or later under certain circumstances. *49 C.F.R. Part 195.452(h)(4)*. PHMSA guidance clarifies that "immediate" repair means that repairs must be effectuated "as soon as practicable." *PHMSA Hazardous Liquid FAQ 7.4*.

In addition to performing required repairs, operators must conduct a risk analysis regarding whether additional preventive and mitigative (P&M) measures are warranted to mitigate the consequences of a failure that could affect an HCA. *49 C.F.R. Part 195.452(i)* (evaluating the likelihood of a pipeline release and how it could affect the HCA based on all relevant risk factors). Specific P&M measures mentioned in the regulations include establishing shorter inspection intervals and installing emergency flow restrictive devices (EFRDs), among others. *49 C.F.R. Part 195.452(i)(1)*. There is, however, no regulatory timeframe associated with implementing P&M measures, and PHMSA has acknowledged that this time period is highly dependent on the proposed P&M measure, noting that while some measures can be implemented quickly, others require significant time for budgeting, engineering and design. *PHMSA Hazardous Liquid IMP FAQ 9.9* ("because of this wide disparity, there is no fixed time requirement for implementing preventive and mitigative actions").

IV. NOPV ITEM BY ITEM ARGUMENT

The issues as joined in this proceeding present questions of law under the Pipeline Safety Act and its implementing regulations at 49 C.F.R. Part 195. The NOPV contains nine claims of alleged violation of law. The Respondent's Request for Hearing contests each of those allegations, asserting that it is possible for pipeline accidents to occur even when an operator is in compliance with the applicable law.

The material facts of the incident, and actions leading up to the incident, are largely undisputed. For the majority of the NOPV Items (Items 1 – 4, 7 and 8), there is no issue of material fact. For those Items, the only potential questions of mixed law and fact can be summarized as follows:

> (1) did the Company conduct a risk assessment that considered LF-ERW seam failure susceptibility, as required by Part 195.452(e)?
>
> (2) did the Company conduct a risk ranking of the pipe segment at issue, as required by Part 195.452(j)(2)?
>
> (3) were the various tools and inspection methods that were employed prior to the incident, as required by Part 195.452(j)(5), designed to reliably detect the anomaly that existed?

As the record reflects that the answer to the above questions is in the affirmative, but the Agency has not provided adequate reasoning to justify its approach to these questions. As the record and exhibits establish, the Company did conduct a risk assessment that considered the risk of seam failure, as well as appropriate risk ranking using all available information. The record also shows that the anomaly at the point of rupture was not detected by the multiple inspection methods and tools employed prior to the incident.

The remaining allegations in NOPV Items 5, 6 and 9 are based upon mistakes of fact, as is demonstrated by record evidence, and therefore cannot be sustained. With all of these factual issues clearly established by the record, only legal questions remain, all relating to the proper

implementation of the Agency's authority under the PSA and the application of the plain language of its regulations.

NOPV ITEM 1: Alleged Failure to Consider Risk of Seam Failure on ERW Pipe

In Item 1 of the NOPV the Agency alleges that the Company did not consider seam failure susceptibility as a risk factor in its IMP program as required by 49 C.F.R. Part 195.452(e)(1). The record clearly shows that the Company did expressly consider seam failure susceptibility for ERW pipe and documented those analyses. Thus, although not stated as such, the NOPV is actually alleging that the Company violated the IMP requirements by not concluding that the pipe was susceptible to seam failure.

This distinction in how the NOPV is drafted is significant. The Agency's IMP regulations do not dictate the conclusion that an operator should reach in following the threat identification and risk assessment process required by Part 195. To the contrary, the regulations require only that an operator fully *consider* all applicable threats, and document that process. EMPCo did just that. The fact that the Company did not *conclude* that the pipe was susceptible to seam failure does not give rise to a violation of applicable law.

Roughly one-fourth of all oil pipelines in the U.S. are LF-ERW.[8] The Agency's approach to consideration of LF-ERW pipe as stated in the NOPV does not follow PHMSA's own rules or precedent. As articulated in this proceeding, PHMSA's approach to LF-ERW pipe would have a significant adverse impact on public safety and energy transportation.

Initial Seam Failure Analyses and Integrity Assessment

EMPCo's written IMP Baseline Assessment Plan was first prepared in 2001 and its IMP plan was finalized in 2002, in close consultation with leading industry experts, such as John Kiefner and Kent Muhlbauer. *Exhibit 1, Kiefner Affidavit* ¶ 10; *Exhibit 2, Muhlbauer Affidavit ¶ 6*. The IMP plan has been reviewed annually and updated over time (with continuing input from Kiefner and Muhlbauer), to reflect changes in the regulations, and to incorporate industry guidance and lessons learned from operation of the EMPCo system. *Id.; see also Exhibit 2, Muhlbauer Affidavit* ¶ 7 (noting that EMPCo's IMP manual "is among the most complete and well-written of any such manuals I have seen"). The Company's IMP program has also been reviewed by PHMSA on multiple occasions (2003, 2007 and 2011), including an in-depth review of the Pegasus system specifically in 2007. The Company addressed all concerns noted by the Agency in those reviews, through further revisions to its IMP plan.[9]

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[8] *PHMSA, Hazardous Liquids Annual Data 2012 (as of May 1, 2014) available at* www.phmsa.dot.gov, (as set forth in annual operator reports submitted in 2013 for the year 2012 and including direct current welded pipe).

[9] As a result of the Agency's 2011 inspection, PHMSA cited EMPCo for violations of Part 195 for which a Petition for Reconsideration is pending. *PHMSA Final Order, CPF No. 4-2011-5016 (June 27, 2013).* As part of that action, PHMSA issued a Compliance Order with two items. Item 1 of the Compliance Order has been stayed pending a decision on the Petition, and EMPCo timely submitted revised procedures under Item 2 of the Compliance Order to the Southwest Region on August 1, 2013. PHMSA Inspector John Pepper responded to the proposed revisions requesting additional modifications on August 5, 2013; EMPCO addressed those in a further revised version submitted to PHMSA on August 29, 2013. To date, the Company has not heard back from PHMSA on those revisions or its Petition for Reconsideration.

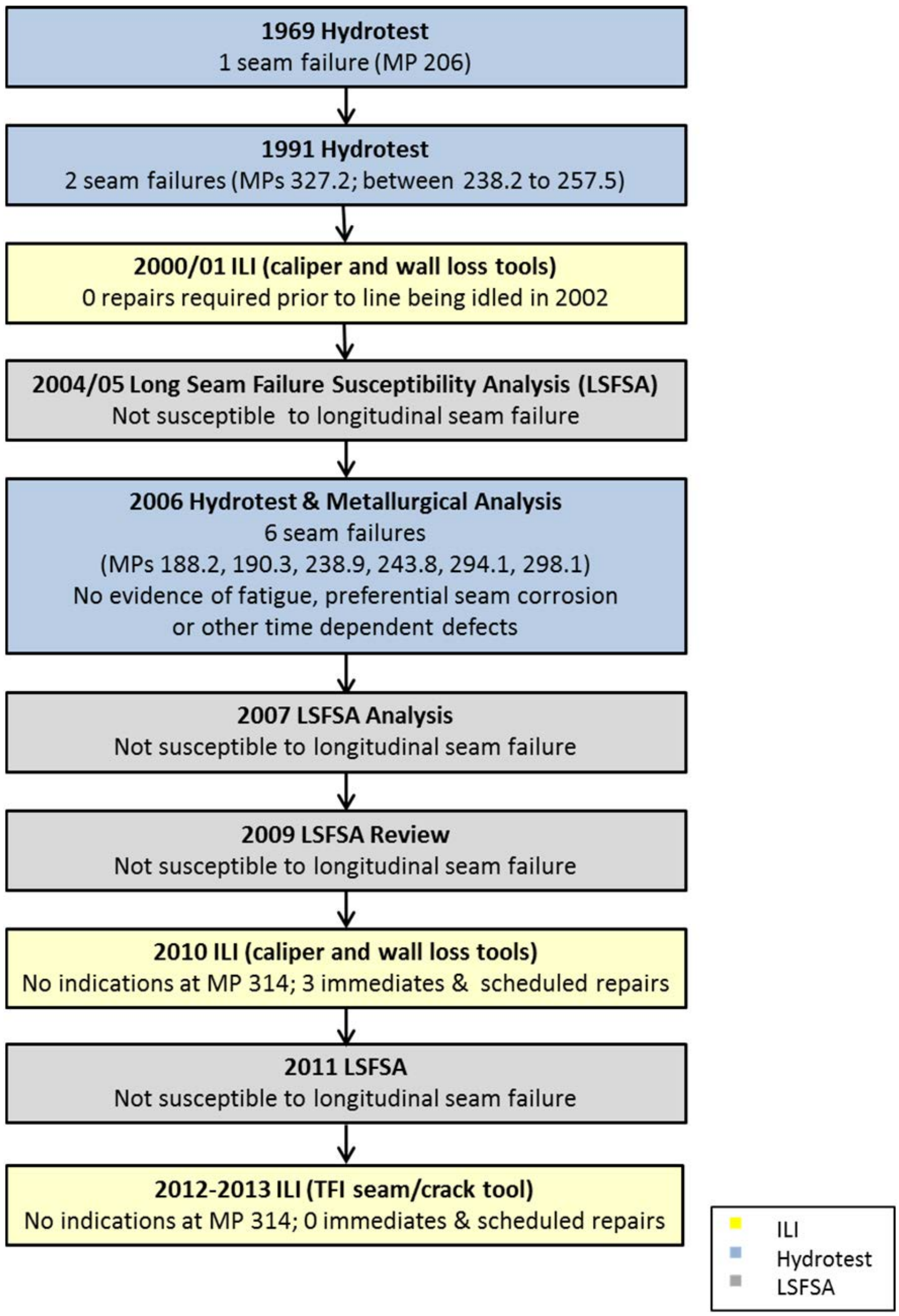
In compliance with the above regulatory requirements and guidance, EMPCo developed a process for analyzing seam failure susceptibility in reliance on the Kiefner and Baker Reports[10] and in consultation with Kiefner himself. *Exhibit 1, Kiefner Affidavit*, p. 2 ¶¶ 11-12. Kiefner created the Pipelife software for the industry at the request of EMPCo to use in analyzing pressure cycling induced fatigue. *Id.* The results of this analysis were expressly considered in EMPCo's Threat Identification and Risk Assessment (TIARA) software inputs, which identify IMP threats and the relevant risk score of a pipeline segment. *Exhibit 13, EMPCo TIARA Foreman to Conway UDT Q&A (6/26/06).* All results were then considered in developing reassessment schedules.

EMPCo first evaluated the pipeline's susceptibility to longitudinal seam failure in late 2004 and early 2005, as the Pipelife software and Baker Report became available. *Exhibit 8, EMPCo Memo regarding Corsicana to Patoka LSFSA (Dec. 10, 2004); Exhibit 9, Memo regarding Corsicana to Patoka LSFSA (Feb. 10, 2005)*; *see Figure 3 EMPCo IMP Assessment and LSFSA: Conway to Foreman.* The Company's 2004-2005 evaluations of the Pegasus Pipeline included consideration of pressure cycling induced fatigue and concluded that the pipe was not susceptible to seam failure. *Id.* Because the line had been idled from 2002-2005, the Company conducted a baseline assessment hydrostatic test in 2005-2006. Following the process developed by Kiefner and reflected in the Baker Report, the failures that occurred during the hydrotest were subsequently repaired and analyzed by an expert metallurgist for evidence of pressure cycling induced fatigue and preferential seam corrosion. *Exhibits 12 and 15, EMPCo Excerpts of Metallurgical Analyses performed by HurstLabs (2006)*; *Exhibit 14, EMPCo Corsicana to Patoka Summary of Hydrotest Learnings (July 6, 2007)*. The results of those analyses did not indicate the presence of either condition. *Id.*

[10] EMPCo has reviewed and updated this process numerous times since its inception, including incorporating updated versions of the Pipelife software, revising the LSFSA analysis, sharing metallurgical findings with Kiefner and Associates in support of industry studies, performing a companywide fatigue screening for all LF-ERW pipelines, and developing a SCADA-based system to detect pressure cycling tends with the potential to shorten the theoretical fatigue lives, among other updates.

Figure 3

EMPCo Integrity Assessment and LSFSA Analysis: Conway to Foreman (prior to March 29, 2013 Mayflower Incident at MP 314.77)



In planning the next integrity reassessment for 2010, the Company's TIARA software accounted for the seam type, history and the long seam failure susceptibility analysis (LSFSA), among other inputs. *Exhibit 13, EMPCo TIARA Foreman to Conway UDT Q&A (June 26, 2006)*. Again, that evaluation did not identify manufacturing or other seam-related threats to the Pegasus Pipeline. *Exhibit 17, EMPCo TIARA Foreman to Conway Manufacturing Threat Classification (July 26, 2006); Exhibit 18, EMPCo TIARA Foreman to Conway Risk Assessment Summary (July 27, 2006)*.

Subsequent Seam Failure Susceptibility Analyses and Reassessment

In 2007, EMPCo performed another LSFSA of the Pegasus Pipeline. *Exhibit 21, EMPCo Foreman to Conway LSFSA and Pipelife Analysis Excerpts (2007)*. Once again, the evaluation concluded that the line was not susceptible to long seam failure.[11] *Id*. The Pipelife fatigue analysis created (and applied in this instance) by Kiefner indicated that the Conway to Foreman segment of the line had a remaining fatigue life of over 373 years and a 180 year reassessment interval.[12] *Id.; Exhibit 1, Kiefner Affidavit* ¶ 14 (stating that the Pegasus Pipeline "appeared to have a theoretical fatigue life in excess of the conservative reassessment interval implemented by EMPCo"). In 2009, after two years of operation and a planned expansion of the pipeline throughput, the Company again reviewed its 2007 long seam failure analysis as well as the metallurgical failure analyses, in preparation for a scheduled 2010 IMP reassessment of the line. *Exhibit 21, EMPCo Patoka to Corsicana LSFSA Review (2009)*; *see also see Figure 3 EMPCo IMP Assessment and LSFSA: Conway to Foreman.*

The Company did run an ILI tool in 2010, although not a seam or crack tool. *Exhibit 50, Final ILI Report Conway to Corsicana (2010)*; *see also Figure 3, EMPCo Conway to Foreman IMP Inspection History*. While the analysis of seam susceptibility did not change, the Company also decided to schedule an ILI TFI seam/crack tool run on the Patoka to Conway section of the line. *Exhibit 29, EMPCO Conway to Corsicana LSFSA and Pipelife Excerpts (2011)*; *Exhibit 35, EMPCo Conway to Corsicana IMP IAD Form 3.2 (Mar. 15, 2011)*. That decision was made to further evaluate the very risk factors that PHMSA now alleges were 'not considered' by the Company. Subsequent long seam failure susceptibility analyses performed in 2011 indicated that the Conway to Corsicana segment of the line still had over 20 years of remaining theoretical fatigue life.[13] *Exhibit 29, EMPCO Conway to Corsicana LSFSA and Pipelife Excerpts (2011); Exhibit 1, Kiefner Affidavit* ¶ 14. Even though it was not required under the regulations, EMPCo assessed the Corsicana to Conway section of the line with a TFI seam/crack tool in 2012 and 2013. *Exhibit 54, EMPCo Conway to Corsicana GE PII TFI Final ILI Report (2013)*. As

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[11] *Exhibit 1, Kiefner Affidavit, ¶¶ 13;19* (noting that "it is reasonable to certify that hydrostatic test failures are not an indication that the pipeline is susceptible to seam failures in the context of Part 195 IMP regulations" where there is no evidence of fatigue related crack growth, selective seam corrosion or other time dependent defects, and explaining that EMPCo's conclusion in this instance was reasonable).

[12] Specifically the Foreman to Conway section of the Pegasus Pipeline had a theoretical fatigue life of 373 years and a reassessment interval of 186.6 years (with a safety factor of 2) with extremely light pressure cycling. *Exhibit 21, EMPCO Conway to Corsicana LSFSA and Pipelife Excerpt (2007).*

[13] This analysis indicated that the Conway to Corsicana segment had 21.8 years of theoretical fatigue life and a reassessment interval of 10.4 years with light pressure cycling. *Exhibit 29, EMPCO Conway to Corsicana LSFSA and Pipelife Excerpts (2011).*

discussed in the preceding sections of this brief at the ultimate point of rupture was discovered reported by the ILI vendor.

EMPCo Exceeded the Minimum IMP Requirements

As made evident by the above actions (documented in the record and attached Exhibits), EMPCo clearly <u>*did*</u> consider the threat of long seam failure on LF-ERW pipe in the Pegasus Pipeline system. *Exhibit 2, Muhlbauer Affidavit* ¶¶ 8, 11-12. Industry expert John Kiefner stated that the Company's conclusion that the failure segment was not susceptible under the federal regulations was reasonable and consistent with available guidance prior to March 29, 2013 and that seam-integrity assessment activities employed on the segment were consistent with the IMP regulations and guidance. *Exhibit 1, Kiefner Affidavit* ¶¶ 19, 21. In undertaking those evaluations, the Company did <u>*more*</u> than the minimum required by IMP rules, not less. *Exhibit 2, Muhlbauer Affidavit* ¶¶ 6-7 (noting that EMPCo's IMP manual "is among the most complete and well-written of the many such manuals I have seen"). Moreover, the Company's IMP plan, procedures and outputs were developed and applied in close consultation with industry experts often used and relied upon by PHMSA, even in the NOPV documentation presented in this proceeding. *See e.g., Exhibit 1, Kiefner Affidavit* ¶10.

PHMSA regulations require pipeline operators to consider risk factors such as susceptibility to seam failure, but they do not require that an operator conclude such a risk exists simply because LF-ERW pipe is present. In this instance, EMPCo clearly did consider seam failure as a risk, and it repeated that evaluation process multiple times, eventually running a seam/crack ILI tool that the Agency alleges should have been run if the Company *had* concluded that a risk of seam failure was present. The seam/crack ILI tool did not identify any actionable anomaly.

The allegations in Item 1 of the NOPV are incorrect, and the alleged violation should be withdrawn.

<u>***NOPV Item 2: Alleged Failure to Establish Five Year Reassessment Interval***</u>

In Item 2, PHMSA alleges that EMPCo failed to establish a five year reassessment interval pursuant to 49 C.F.R. Part 195.452(j)(3). That allegation hinges on the Agency's assertion in NOPV Item 1 that the Company should have determined that the Pegasus Pipeline was susceptible to seam failure. The NOPV asserts that the Company should have concluded, on the basis of the 2005 and 2006 BAP hydrotests, that the line was in fact susceptible to seam failure and should have established a five year reassessment interval. As discussed above in response to Item 1, the Company did carefully consider the 2005–2006 hydrotest data with regard to the risk of seam failure. The Company also consulted with both Kiefner and Muhlbauer on these issues. *Exhibit 1, Kiefner Affidavit* ¶¶ 11-12; *Exhibit 2, Muhlbauer Affidavit* ¶ 6. The conclusion from that review was that there was no evidence of either pressure cycling induced fatigue or preferential seam corrosion. *Exhibit 14, EMPCo Corsicana to Patoka Summary of Hydrotest Learnings (July 6, 2007)*; *Exhibit 21, EMPCo Foreman to Conway LSFSA and Pipelife Analysis Excerpts (2007)*; *see also Exhibit 1, Kiefner Affidavit* ¶¶ 19, 21.

Because the Company's analysis of seam failure susceptibility concluded that the Pegasus Pipeline was not susceptible under the federal regulations, there was no requirement under IMP to schedule a seam tool. Thus, the Company did not violate the requirement to establish a five year reassessment interval for a seam or crack ILI tool.

The Agency's allegations in Item 2 of the NOPV can only have relevance if the allegations in Item 1 are deemed correct. Since the Company clearly *did* consider the risk of seam failure susceptibility (Item 1) and concluded that the risk was not significant, then there was no requirement to establish a five year interval to reassess the risk not found (Item 2). PHMSA's allegations therefore fail in both Item 1 and Item 2. Because the pipeline was not determined to be susceptible to seam failure in accordance with applicable law and guidance, no seam/crack tool inspection was required to be performed on five year intervals.

Ironically (in light of the allegations of the NOPV), the Company did run a seam ILI tool to further evaluate the potential risk of seam failure, even though it was not required to do so. And the Company continued to review its reassessment and tool type schedules based on pressure cycle fatigue calculations using the Pipelife software developed for EMPCo by Kiefner. *Exhibit 1, Kiefner Affidavit* ¶¶ 19, 21 (noting that EMPCo's activities were consistent with the regulations and the Baker Report flow chart). As explained in the Baker/Kiefner Report:

> If no fatigue-related failures exist, it is reasonable to certify that the pipeline is not susceptible to seam failures in the context of federal integrity management requirements. This does not, however, necessarily preclude the need for periodic reassessment. A reassessment interval should be calculated using the best available information. As more information is gained and new tools developed, the need for and timing of future reassessments can be re-evaluated.

Baker/Kiefner Report, p. 26; *see also Exhibit 1, Kiefner Affidavit* ¶ 13 (noting that if there is no evidence of fatigue related crack growth, selective seam corrosion or evidence of other time dependent defects such as stress corrosion cracking, "it reasonable to certify that the hydrostatic test failures are not an indication that the pipeline is susceptible to seam failures in the context of the Part 195 IMP regulations"). In doing all of this, the Company was expressly going beyond the regulatory requirements, in keeping with the Agency's directive that an operator's integrity management program should be a dynamic and iterative process.

The allegations in Item 2 of the NOPV are incorrect, and the alleged violation should be withdrawn.

NOPV ITEM 3: Alleged Failure to Follow IMP Plan Procedure

In Item 3 of the NOPV, the Agency alleges that EMPCo failed to follow its own IMP procedure found at Section 5.1 of its IMP Manual. That procedure implements the requirements of Part 195.452(j)(3), to provide for "continual evaluation and assessment" of pipeline segments subject to IMP. The NOPV specifically alleges that the Company improperly changed the timing of a planned ILI for the pipeline, extending it from "prior to [the end of] 2011" to late 2012 or early 2013, without providing advance notice to PHMSA.

As discussed in response to Items 1 and 2 above, the Company properly followed the IMP regulations by considering whether the pipe at issue was susceptible to long seam failure, in compliance with 49 C.F.R. Part 195.452(e)(1). This consideration was fully documented, and included input and review by John Kiefner, whom the Agency recognizes as a national expert and who created the PHMSA-endorsed process for evaluation of LF-ERW longitudinal seams under IMP.

Following its IMP procedure, the Company concluded that the pipe segment was not susceptible to seam failure in 2007, 2009 and again in 2011. PHMSA reviewed EMPCo's IMP procedures and LSFSA analysis on multiple occasions (2003, 2007 and 2011), including an in-depth review of the Pegasus system specifically in 2007, and did not raise any concerns.[14] As a result of the Company's determination that the line was not susceptible to seam failure, no seam reassessment was required. Based on the 2010 ILI on the segment at issue and subsequent risk analysis, the next required integrity reassessment date was July of 2015. The Company nevertheless elected to run a seam tool ILI well in advance of that date, which was not required by the rules because the pipe was not deemed susceptible to seam failure. As this tool run was not required, it was not subject to the variance reporting requirements at 49 C.F.R. Part 195.452(j)(5) or EMPCo's IMP manual. *See Exhibit 4, EMPCo IMP Manual Excerpts Section 5.1(4) Continual Evaluation*. The seam/crack tool ILI was voluntarily run in advance of the incident, but no actionable anomaly at the point of rupture was reported by the ILI vendor.

The fact that the Company elected to use the seam/crack ILI tool even though it was not required illustrates EMPCo's diligent and proactive approach, and willingness to go beyond minimal requirements. The ILI tool that the Agency insists should have been run was, in fact, run well in advance of the required reassessment interval, and before the incident occurred. Because it was a discretionary tool run, there was no requirement to provide written notice to the Agency or complete a Management of Change (MOC) document and the Company was free to modify its internal schedule for such a discretionary action. The Company ***did*** meet the reassessment intervals for ILI referenced by PHMSA and it ***did*** voluntarily run a seam tool even though not required. Most significantly, that tool run did not report any actionable anomaly, which further supports the fact that the Agency's complaint in this Item is both unfounded and irrelevant.

The allegations in Item 3 of the NOPV are incorrect, and the alleged violation should be withdrawn.

NOPV Item 4: Alleged Failure to Prioritize Pipeline Segments for Reassessment in Integrity Assessment Schedule that Posted Highest Risk to HCAs

The Agency alleges in Item 4 of the NOPV that the Company failed to prioritize the Pegasus Pipeline segments that posed the highest risk to high consequence areas (HCAs) before reassessing lower risk segments. Citing 49 C.F.R. Parts 195.452(e) and (j)(3) again, the Agency alleges that EMPCo failed to prioritize the Corsicana to Conway segment higher than the Patoka to Conway segment for reassessment related to manufacturing flaws and seam failure susceptibility. The record clearly shows, however, that the Company ***did*** carefully consider all identified risk factors in planning the reassessment intervals for the Pegasus Pipeline and that those considerations were well documented.

The Company properly followed the IMP regulations by considering all risk factors reflecting the risk conditions on the segments as required under 49 C.F.R. Parts 195.452(e) and 195.452(j)(3). *See Exhibit 2, Muhlbauer Affidavit* ¶¶ 11-12 (stating that EMPCo "properly recognized the issues associated with LF-ERW pipe, reacted to the threats on the Pegasus pipeline, and complied with the Part 195 IMP regulations"). EMPCo's risk assessment process was drafted with input and review from Kent Muhlbauer, a nationally recognized expert on

[14] As discussed supra at p. 11.

pipeline risk management. *Exhibit 2, Muhlbauer Affidavit* ¶¶ 6-7. As discussed above, the IMP rules _do not_ mandate how operators assign risk scores to each risk factor or how they prioritize assessments, but require that operators consider the regulatory factors and conduct a meaningful analyses of their particular systems.

As described above, following its IMP procedures, the Company's risk assessments and evaluation did not identify long seam failure susceptibility or manufacturing as risks to either the Patoka to Conway or Conway to Corsicana segments. *Exhibit 19, EMPCO Risk Assessment Summaries for Patoka to Corsicana (2006).* Further, the 2007 risk scores on both segments were practically identical.[15] Even though it was not required under Part 195 or EMPCo procedures, when planning the reassessment tools in 2009, the Company made the decision to assess the Patoka to Conway segment with a TFI seam/crack tool. This decision was based on the fact that, as compared to the Conway to Corsicana segment, the Patoka to Conway segment experienced more hydrostatic seam failures on a LF ERW per mile basis, more pressure reversals, and shorter fatigue lives based on 2007 data.[16] *Exhibit 22, EMPCO Patoka to Corsicana LSFSA Review (2009).* In addition, the Patoka to Conway segment experienced three girth weld leaks that were not present on the Conway to Corsicana segment.

As with Items 1-3 of the NOPV, Item 4 is based on an inaccurate and improper assumption and should be withdrawn. The Company considered seam susceptibility many times, and concluded that no significant risk was present. Given such well-documented and careful consideration of all known risk factors, there was no legal requirement to run a seam/crack tool, there was no obligation to schedule a five year reassessment interval of a tool not required, and there was no requirement to prioritize one segment differently than another. A seam tool was voluntarily run, resulting in no reported anomalies at the point of failure.

NOPV Item 5: Alleged Failure to Take Prompt Action to Address All Anomalous Conditions by Not Declaring Discovery of Immediate Repair Conditions

PHMSA alleges that EMPCo failed to declare discovery of immediate repair conditions from information received in preliminary reports from the ILI vendor, and, as a result, treated "Immediate Conditions" as "Validation Digs" or "Confirmation Digs." The Agency argues that this failure led to a violation of 49 C.F.R. Part 195.452(h) because EMPCo failed to take appropriate action for "Immediate Conditions." PHMSA claims that EMPCo received a preliminary report on August 9, 2010, identifying two "Immediate Conditions" at MP 164.051 and MP 142.394. The Agency further alleges that MP 164.051 was not addressed until August 28, 2010, and that MP 142.394 was not addressed until several months after the report on January 6, 2011. PHMSA's allegations are unfounded, and based on incorrect factual assumptions and conclusions.

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[15] The TIARA risk scores on the Patoka to Conway and Conway to Corsicana segments in 2006 were roughly the same, both in the D3 range on the EMPCo IMP Risk Matrix. Pursuant to the EMPCo Risk Matrix Methodology, a score of D3 estimates that the probability of an event is very unlikely and that the consequences of an event may include restricted work or medical treatment and/or potential short term or minor adverse environmental impacts, among other consequences. *Exhibit 6, Attachment #1 to EMPCO OIMS System 2A.* For this risk category, there are no further (P&M) actions to consider. *Id.*

[16] The EMPCo 2011 fatigue analyses cited in the NOPV were not performed until after the 2010 assessments were completed.

In the first instance, the anomaly at MP 164.051 was identified as a 72% external metal loss call in a preliminary report dated and received by the Company on August 23, 2010. *Exhibit 23, EMPCo Email from NDT (8/23/10)*; *Exhibit 24, EMPCo NDT Preliminary ILI Report (Aug. 23, 2010)*. PHMSA's erroneous allegation that the report was received on August 9, 2010, is based on the date of an underlying dig sheet maintained by the vendor, not the date the preliminary report was received by EMPCo. Ironically, PHMSA correctly notes the receipt of the preliminary report in the Table included in NOPV Item 6 (last line, second column). The Company factored in tool tolerance and declared discovery of this anomaly as a potential immediate repair on *the same day* it received the preliminary report, August 23, 2010. The anomaly was repaired just five days later, on August 28, 2010. *Exhibit 25, EMPCo Repair Form PL-0751 (Aug. 28, 2010).*

EMPCo became aware of the second anomaly, MP 142.394, in the *final* report received by the Company from the vendor on January 10, 2011.[17] *Exhibit 30, Email from NDT and MP 142.39 Dig Sheet (Jan. 10, 2011).* This anomaly was not identified in any preliminary report. The anomaly was found to be a 0.74% top dent with an external corrosion pit, believed to be associated with original construction. The Company acted within two days of receiving the final report, repairing the anomaly on January 12, 2011. *Exhibit 31, EMPCo Repair Form PL-0751 (Jan. 12, 2011).*

The factual basis for the allegations in NOPV Item 5 are simply inaccurate and the suggestion of any violation is without foundation and should be withdrawn. As set forth above and reflected in the record, EMPCo complied with the discovery deadline for "Immediate Conditions" set forth by the applicable regulations in both instances cited by PHMSA.

NOPV Item 6: Alleged Failure to Declare Discovery of Condition within 180 Days

In Item 6 of the NOPV, PHMSA alleges that EMPCo failed to declare discovery within 180 days on four separate occasions on the Patoka to Corsicana segments of the Pegasus Pipeline in 2010, 2011 and 2013. PHMSA specifically asserts that EMPCo had sufficient information from the ILI vendor to make such determinations, again citing to 49 C.F.R. Part 195.452(h). To the contrary, the record confirms that in all instances the tool vendor did not provide EMPCo with the ILI data until nearly the conclusion of the 180-day period, making it impracticable to declare discovery within the 180 day timeframe. *Exhibit 26, EMPCo IMP Form 1.2 (Dec. 17, 2010); Exhibit 33, EMPCo IMP Form 1.2 (Jan. 31, 2011); Exhibit 38, EMPCo IMP Form 1.2 (Aug. 2, 2013); Exhibit 39, EMPCo IMP Form 1.2 (Aug. 28, 2013)*. Consistent with IMP regulations, the Company's IMP Manual provides that discovery is required within 180 days of running the ILI tool, unless there are circumstances that make discovery impractical. *Exhibit 4, EMPCo IMP Manual Excerpts Section 4.4 Timeliness of Discovery; 49 C.F.R. Part 195.452(h)(2).* Until the Company can verify the ILI vendor data and complete data integration, the Company does not have sufficient information to declare discovery. The Company followed its procedure, as established in its IMP Manual, to extend the 180-day timeframe with adequate justification. *See Figure 4, Summary of Discovery Dates for ILIs Referenced in PHMSA NOPV.*

[17] The PHMSA PSVR includes as support a PL-0751 repair form associated with a ***different*** immediate anomaly located at MP 274.091 and odometer number 296278.97. This anomaly was discovered when EMPCo received the final ILI report on January 10, 2011 and was repaired on January 13, 2011 (when the inspector signed the repair form). *Exhibit 32, EMPCo Repair Form PL-0751 MP 274.09 (Jan. 13, 2011).*

Figure 4: Summary of Discovery Dates for ILIs Referenced in PHMSA NOPV

ILI Tool (date completed)*	Date of Final Report	Date(s) of IMP Form 1.2 Extension Request	180 Day Deadline	Date of Discovery	Revised Deadline**
Patoka to Conway					
MFL-Combo and TFI (8/15/10)	12/30/10	1/31/11	2/11/11	3/4/11	3/11/11
Conway to Corsicana					
MFL Combo (7/21/10)	1/7/11	12/17/10	1/17/11	3/15/11	3/17/11
TFI (2/6/13)	8/29/13	8/2/13; 8/28/13	8/5/13	10/7/13	10/7/13

*This is the date the last tool entered the receiving trap.
**Exception approved due to delayed receipt of final ILI vendor report.

The Agency's allegations in this instance are unfounded, given that the Company followed its procedures and the IMP regulations. Moreover, it is peculiar that PHMSA would allege this violation given that the Agency has not even responded to EMPCo on proposed revisions to its IMP Manual on this very issue of whether an operator has sufficient information to declare discovery.[18]

NOPV Item 7: Alleged Failure to Follow Procedure for Updating Risk Assessments as Changes Occur

PHMSA alleges in Item 7 that EMPCo did not follow internal procedures IMP 5.4 and OIMS 2.4 regarding updating risk assessments in response to potential threat changes, citing again to 49 C.F.R. Parts 195.452(b)(5) and (j). The Agency argues that EMPCo should have updated its risk assessment when the Company extended the inspection timing of the TFI seam/crack tool on the Conway to Corsicana segment and that this omission resulted in the failure to identify threats and preventive and mitigative measures. In contrast, the record shows that no updated risk assessment was required under EMPCo IMP 5.4 or OIMS 2.4.

[18] In 2013, PHMSA cited EMPCo for a similar violation in a prior NOPV for which a Petition for Reconsideration is pending. *PHMSA Final Order, CPF No. 4-2011-5016 (June 27, 2013)*. As part of that action, PHMSA issued a Compliance Order with two items. Item 1 of the Compliance Order has been stayed pending a decision on the Petition, and EMPCo timely submitted revised procedures under Item 2 of the Compliance Order to the Southwest Region on August 1, 2013. PHMSA Inspector John Pepper responded to the proposed revisions requesting additional modifications on August 5, 2013; EMPCO addressed those in a further revised version submitted to PHMSA on August 29, 2013.

EMPCo OIMS Element 2.4 states that "risk assessments are updated at specified intervals and as changes occur" and EMPCo IMP Section 5.4 requires annual review of integrity conditions and when significant changes occur, an updated risk assessment. *Exhibit 5, EMPCo OIMS Framework Element 2.4; Exhibit 4, EMPCo IMP Manual Excerpt Section 5.4.* As discussed above, the March 2011 long seam failure susceptibility analysis determined that the Conway to Corsicana segment was not susceptible to seam failure and identified a conservative interval for seam reassessment by the summer of 2013. *Exhibit 29, EMPCo Conway to Corsicana LSFSA and Pipelife Analysis Excerpts (2011); Exhibit 35, EMPCo IMP IAD Form 1.2 Conway to Corsicana (3/15/2011).* Because this analysis did not change after March 2011 and no other integrity conditions changed, there was no requirement to revise the risk analysis. Further, a revised analysis would not have impacted the threat identification or any of the preventive or mitigative measures for this segment because the risk analysis did not rely upon the implementation of a seam/crack tool inspection in 2011 or 2012.

The allegations of Item 7 of the NOPV are without foundation because the requirement in EMPCo's procedures to perform an updated risk assessment did not apply in this instance. The fact that the Company recommended, scheduled, and employed a TFI seam/crack tool in advance of the conservative Pipelife reassessment interval demonstrates that EMPCo's IMP exceeded Part 195 integrity management rules. Moreover, it is illogical to assume that the anomaly at the ultimate point of rupture would have been reported by an earlier TFI seam/crack tool run. No anomaly was reported when EMPCo ran the tool in 2012-2013. Given that crack growth is associated with the passage of time, the anomaly at the point of rupture was even less likely to be detected at the earlier date when PHMSA alleges the tool should have been run.

<u>NOPV Item 8: Alleged Failure to Follow O&M Procedure by Selective Use of Threat Identification and Risk Assessment Manual Process Results</u>

In Item 8 of the NOPV, the Agency alleges that EMPCo failed to follow its Operations and Maintenance (O&M) procedures required under 49 C.F.R. Part 195.402 by selectively using its TIARA process in 2011, and that this led to a failure to properly characterize the result of a release to certain HCAs on the Conway to Foreman segment, including the Lake Maumelle Watershed. In actuality, the Agency appears to be asserting a violation of the IMP threat identification and analysis requirements set forth in 49 C.F.R. Part 195.452. The record clearly shows, however, that the Company's IMP, Operations Integrity Management System (OIMS), and TIARA procedures were consistent with applicable law. Further, EMPCo properly applied those processes which led to the identification of certain preventive and mitigative (P&M) measures to protect HCAs, including scheduling the installation of three emergency flow restriction devices (EFRDS) (two in the Lake Maumelle area) and running a TFI seam/crack tool. *Exhibit 36, EMPCo Conway to Corsicana P&M Form 6.1 (7/21/11); Exhibit 37, EMPCO Conway to Corsicana EFRD Form 6.2 (7/21/11).*

As discussed above, when performing its risk assessment analysis and continual evaluation, the Company properly followed the relevant Part 195 regulations and its own procedures which were drafted with input from key industry experts. *Exhibit 2, Muhlbauer Affidavit* ¶¶11-12 (stating that EMPCo "properly recognized the issues associated with LF-ERW pipe, reacted to the threats on the Pegasus pipeline, and complied with the Part 195 IMP regulations"). EMPCo identified HCA locations and types, including Lake Maumelle and other water bodies, and included them in the TIARA risk assessment dynamic segmentation and calculations. *Exhibit 7, EMPCo TIARA Manual Excerpts; Exhibit 28 EMPCO TIARA UDT Q&A Conway to Corsicana (2011)* (assessing a score of 57 for sensitive receptors above a 55 for high level of public concern). In addition, these sensitive areas and drinking water bodies were expressly considered in the Company's IMP P&M measures analysis. *Exhibit 36, EMPCo Conway to Corsicana P&M Form 6.1 (7/21/11)* (considering whether drinking water bodies are potentially affected HCAs)*; Exhibit 37, EMPCO Conway to Corsicana EFRD Form 6.2 (7/21/11)*(considering the same).

In 2011, the TIARA process did not result in any identified threats and did not in turn trigger any requirement to re-characterize the risk of release to HCAs on the Conway to Corsicana segment. *Exhibit 34, EMPCo Conway to Corsicana Manufacturing Risk Assessment (2011)*; *Exhibit 36 Conway to Corsicana P&M Form 6.1 (7/21/11)*. Despite this fact, and the fact that a valve would not significantly reduce the modeled risk or consequence as defined by the regulatory criteria and TIARA modeling, EMPCo's IMP Data Integration Team recommended further review of proposed EFRD sites in the Lake Maumelle watershed area and the Cedar Creek Reservoir as risk reduction measures. *Exhibit 37, EMPCO Conway to Corsicana EFRD Form 6.2 (7/21/11).* This led to the decision to install three EFRDs in this area. As noted by risk management expert, Kent Muhlbauer, "risk reduction measures were chosen in proportion to perceived risks and in light of other potential incident scenarios, consistent with requirements and objectives of regulatory IMP." *Exhibit 2, Muhlbauer Affidavit* ¶ 12.

The allegations of Item 8 of the NOPV are without foundation because the Company complied with its own procedures and with applicable law. The fact that the Company identified the potential need for EFRDs in HCAs along the Conway to Corsicana segment shows EMPCo's diligence in going beyond minimal Part 195 requirements.

NOPV Item 9: Alleged Failure to Follow Procedure for Continual Evaluation and Assessment

In Item 9 of the NOPV, the Agency alleges that EMPCo failed to follow its Management of Change (MOC) procedure OIMS 7.2 when it merged testable segments in 2009. PHMSA contends that the longer testable segments negatively impacted the TIARA risk assessments by diluting risk scores on the Conway to Foreman segment. The record will show, however, that EMPCo complied with this its MOC procedure and that merging the segments could not have negatively impacted the risk assessment.

EMPCo's OIMS Management of Change process ensures that operational, procedural and physical changes are implemented in a systematic manner intended to ensure the integrity of EMPCo facilities. *Exhibit 5, EMPCo OIMS Framework Element 7.2***.** As discussed above, the Company completed MOC forms in 2005 that expressly considered the impact of the merger of testable segments on IMP risk assessments and concluded that there was no negative impact to the integrity risk assessment process. *Exhibit 10, EMPCo Management of Change Form No. 05-*

2829 (8/10/05); Exhibit 11, EMPCo Management of Change Form No. 05-2833 (8/10/05). Under the EMPCo TIARA dynamic risk segmentation, threats cannot be aggregated or masked over multiple miles. For that reason, the length of a testable segment does not impact the risk to any specific area of the pipeline. In short, the Company combined the testable segments in compliance with applicable law and this decision did not mask risk on the intermediate segments.

V. <u>THE PROPOSED PENALTY IS NOT WARRANTED</u>

A. <u>Strict Liability is not Provided in the PSA, thus there is No Basis for the Alleged Violations or Proposed Administrative Penalties</u>

As discussed in the preceding sections of this brief, the NOPV presumes that simply because an incident occurred, there have been violations of PHMSA's Part 195 regulations. That presumption would only apply if the PSA had a strict liability provision, but it does not. Although infrequent, it is possible for an incident to occur even when a pipeline operator has fully complied with applicable law. This is one such instance.

In the absence of regulatory violations, there is no basis for administrative penalties. EMPCo was in compliance with PHMSA's Part 195 regulations in regard to the Pegasus Pipeline. Thus, the alleged violations asserted in the NOPV are based on mistakes of fact and law and should be withdrawn entirely. In that event, no penalty is appropriate.

B. <u>Even if it is Found that Violations did Occur, the Amount of the Penalty Proposed is Unwarranted</u>

The Agency's proposed penalty of more than $2.6 million is not authorized by law. The penalty provisions of the PSA establish three limitations on the amount of civil penalties proposed in any PHMSA enforcement proceeding. First, Section 2 of the PSA establishes factors that the government must ("shall") consider in developing an appropriate proposed civil penalty for a pipeline incident. *49 U.S.C. § 60122(b)* (those factors appear again in PHMSA regulations at 49 C.F.R. Part 190.225). Second, any violation occurring prior to January 3, 2012, must be limited to a maximum penalty of $100,000 per day. *49 U.S.C. § 60122(a)(1).* Third, any "related series of violations" occurring prior to January 3, 2012, must be capped at no more than $1 million. *49 U.S.C. §60122(a)(1); 49 C.F.R. Part 190.223(a).*[19] Each of the nine Items in the NOPV is alleged to have commenced prior to January 3, 2012. Moreover, many of the allegations rely on the same purported evidence, thus the statutory cap of $1 million should apply.

[19] In reviewing the issue of civil penalty caps in the Pipeline Safety Act (PSA) during reauthorization efforts preceding the enactment of the Pipeline Safety Improvement Act of 2002, Senators Hollings and Kerry had the following exchange on the phrase "related series of violations": [Sen. Hollings]: "*I am seeking clarification that all information requests issued by the Secretary pursuant to a single incident investigation are considered "related" for purposes of calculating the $1,000,000 civil penalty cap for a 'related series of violations'…*" [Sen. Kerry]: "*It is the intention of this legislation to treat all information requests pursuant to a single incident investigation as 'related' for purposes of applying the civil penalty cap…" Senator Hollings (SC) and Senator Kerry (MA). "Pipeline Safety Improvement Act." Congressional Record 146:103 (Sept. 7, 2000), p. S8235.*

1. PHMSA's Statutory Penalty Authority

Until recently, PHMSA had not assessed administrative civil penalties in excess of the daily or "related series of violations" maximums, thus the manner in which PHMSA seeks to use its penalty authority is an issue of critical importance for both the Agency and the industry. The statutory language authorizing PHMSA penalty authority has not changed since it was enacted more than thirty years ago (other than to increase the maximum amounts available), and there is very little legislative history providing guidance on how the Agency should exercise its penalty authority. Similarly, the Agency has not issued any regulation or policy describing how it will apply its penalty authority, or how it intends to interpret the phrase "a related series of violations."

The only relevant guidance that the Agency has issued to date is its decision *In re: Colorado Interstate Gas Co., CPF 5-2008-1005 (Nov. 23, 2009) (CIG)*. In *CIG*, the Agency stated that it interpreted the phrase "related series of violations" to mean "a series of daily violations" of the same regulatory requirement. *Id. at p. 11*. To do otherwise, the *CIG* decision reasoned, "would effectively limit the number of violations that PHMSA could assess penalties on" in a given incident. *Id.* We disagree. Congress could have stated (and has, in other statutes[20]) that the penalty cap applied only to "multiple violations of a single requirement," but it did not use that language. Instead, it established a cap on "related series of violations." As noted in the Congressional Record, Senators Kerry and Hollings interpreted this phrase to mean "all violations related to a single incident,"[21] and that is the interpretation that it should be given in this proceeding. The statutory language is further supplemented by the *CIG* decision where the Agency held that Items in a NOPV may also be "related" (even if not daily violations of the same requirement) if the facts and law for the claims are "so closely related … that they are not separate and should be considered one violation." *CIG*, at 12.

2. The NOPV As Drafted Alleges a "Related Series of Violations"

Following the reasoning of the *CIG* decision (and the clear language of the statute), Items 1, 2, 3 and 4 of the NOPV in this case are clearly related. All four of those Items are inextricably intertwined, relying on the same facts and law. The essence of the Agency's claims for Items 1 through 4 of the NOPV is that EMPCo failed to properly conclude that the pipe segment at the point of rupture was susceptible to seam failure. As stated above in this brief, the Company believes that the IMP rules do not dictate a particular conclusion, but only a deliberative process. The Company undertook that process and documented it. Unfortunately, an incident occurred, despite the fact that the Company followed applicable law, and despite the fact that state of the art technology did not detect an actionable anomaly at the point of rupture prior to the incident.

But for the Agency's allegation that the Company failed to conclude that the pipe segment was susceptible to seam failure, there would be no basis for the purported violations asserted in Items 1 through 4. Item 1 specifically addresses the alleged failure to conclude that the pipe was susceptible to seam failure. Item 2 builds on that same allegation, by asserting that *because* the

[20] *See e.g., Social Security Act*, 42 U.S.C. §1320(d)5(a)(3) (setting a maximum cap multiple violations of a single requirement).

[21] *See* f n. 19.

Company did not conclude that the segment was susceptible to seam failure, it exceeded the length of time allowed to run a seam ILI tool (note that the Company ran other ILI tools during the five years in issue; it ***did*** run a seam tool only a few months after the five years in issue, even though not required by law; and the ILI seam tool was run before the incident occurred, reporting no actionable anomaly at the point of rupture). The Agency's PSVR cites the same evidence in support of both Items 1 and 2 (hydrostatic test data and IMP assessment worksheets). *PSVR, pp. 7, 13.*

Items 3 and 4 of the NOPV continue this reliance on a single allegation, using similar evidentiary support and referencing either directly or indirectly the same Part 195 regulations. Item 3 asserts that the Company failed to complete a Management of Change form for extending the five year reassessment interval invoked in Item 2. Again, but for the presumption that the rules require an operator to ***conclude***, not just consider, that LF-ERW pipe is susceptible to seam failure, then there is no basis for a violation in Item 3 (or 1, or 2). The same holds true in regard to Item 4, which alleges – again – that because EMPCo failed to conclude the pipe was susceptible to seam failure, it did not properly prioritize the timing of the ILI seam tool runs on segments of the Pegasus pipeline.

There is only one alleged fact central to Items 1 through 4 of the NOPV, being that the Company failed to conclude seam failure susceptibility. Without that assertion, there is no basis for any violation of law in any of these four Items. For that reason, using both the plain language of the statute and the rationale articulated by the Agency in the *CIG* decision, Items 1 through 4 of the NOPV constitute "a related series of violations" that are "so closely related … that they are not separate and should be considered one violation." *CIG*, at 12.

Items 1 through 4 of the NOPV should be combined for proposed penalty purposes, with the combined penalty not to exceed $1 million.

3. The Proposed Penalty Fails to Consider and Appropriately Apply All Mitigating Factors

Even if the Agency (or the courts) concludes that Items in the NOPV are not a "related series of violations" in whole or in part, and thus not subject to the $1 million penalty cap, the combined proposed penalty does not take into account all factors associated with the incident, as required by the PSA and PHMSA regulations.[22] EMPCo requested and was provided a copy of PHMSA's PSVR for this matter, and although it does not specifically provide numeric penalty calculations (see discussion in Section 4 below), the PSVR does provide the Agency's mitigating factor analysis (*i.e.*, nature, circumstances, gravity, culpability, good faith, and other matters as justice may require) for each alleged violation. EMPCo does not intend to address each component of each violation, but it generally contests the mitigation analysis set forth in the PSVR. For instance, the report repeatedly alleges that the Company made conscious decisions not to comply with regulatory requirements that were clearly applicable,[23] and that it did not

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[22] 49 C.F.R. Part 190.225 states that "in determining the amount of a civil penalty…the [Agency] *shall* consider," among other things, the nature, circumstances and gravity of the alleged violation, as well as any good faith by the Respondent in attempting to achieve compliance. *49 C.F.R. Part 190.225* (emphasis added).

[23] PHMSA's own PSVR notes that EMPCo's response to the incident was timely, appropriate and in accordance with the Company's procedures. *PHMSA PSVR, CPF 4-2013-5027, pp. 11, 14.*

make reasonable interpretations of regulatory requirements. The record in this matter shows that the Company clearly complied with applicable regulatory requirements regarding IMP, and that it did not at any time make conscious decisions to disregard the law.

In addition, although the specific calculations of the proposed penalty have not been made available, the proposed penalty does not appear to consider the fact that EMPCo fully cooperated with all federal, State and local officials in good faith while responding to and investigating the causes of the incident. To date, the Company has spent more than $75 million in response to the Mayflower incident, and continues to review and revise its Integrity Management Program as a result of the incident. If for no other reason, the penalty proposed in this NOPV should be reduced in light of the cooperation and good faith shown by EMPCo in its efforts both during and after the incident, both of which are mitigating factors set forth in 49 C.F.R. Part 190.225.

4. Due Process Requires that an Agency's Penalty Rationale Be Articulated

Finally, the proposed penalty for this matter should be reduced for due process and policy reasons, because the NOPV as issued provided no explanation for the basis of the penalty, which on its face exceeds the statutory cap. PHMSA practice has evolved in recent years in terms of how the Agency interprets and applies its penalty authority. At present, the Agency does not provide any explanation in a NOPV of how a penalty was derived, or whether multi-day assessments are included.

Although many administrative agencies have published official penalty policies to explain how they intend to interpret and apply their statutory penalty authority, PHMSA has promulgated no such policy. Nor has it produced any guidance, interpretative letters or advisories for the regulated community and the public to refer to in anticipating how the Agency should or will exercise its penalty authority.

The Administrative Procedure Act (APA) requires that respondents be informed of "the matters of fact and law asserted" in any enforcement pleading, which should include a clear statement of the theory on which the agency will proceed with its case, such that the respondent understands the issues and is afforded full opportunity to present its defense at a hearing. *5 U.S.C. 554(b); Yellow Freight System v. Martin, 954 F.2d 353, 357 (6th Cir. 1992).*

PHMSA's failure to expressly allege multi-day or statutory maximum claims in its NOPV violates the due process requirements of the Constitution and the procedural requirements of the APA. As a matter of equity, policy and due process considerations, the Agency should reduce the proposed penalty in this matter. Penalty adjustment in this instance would benefit both the Agency and the regulated community by clarifying the application of the *CIG* decision.

VI. THE PROPOSED COMPLIANCE ORDER IS OVERBROAD

The Proposed Compliance Order (PCO) requests actions by the Company to review and improve management systems in regard to Items 1, 2, 5, 6 and 8 of the NOPV. There are nine separate

substantive paragraphs in the PCO.[24] Paragraph 1 of the PCO is notably more expansive than the other elements of the PCO.

Paragraph 1 relates to Item 1 of the NOPV, and requests that the Company modify its IMP procedures concerning seam failure susceptibility analyses, seam integrity assessment plans and threat modeling. Item 1 of the PCO is intended to broadly address "all pre-70 ERW pipe *on any assets covered by the operator's IMP*." NOPV, p. 10 (emphasis added). None of the other requested actions in the PCO address "all assets" of the Company. Such an extension of requested relief regarding modification of IMP procedures relating to pre-70 ERW pipe outside of the Pegasus system goes beyond the specific facts and issues presented in the NOPV, and exceeds the scope of relief necessary to remedy the alleged harm in this case.

Established law holds that injunctive relief must be narrowly tailored to remedy the specific harm alleged, and that an overbroad scope of injunctive relief is an abuse of discretion. *Ahearn ex rel. N.L.R.B. v. Remington Lodging & Hospitality, 842 F. Supp. 2d 1186, 1205-1206 (D. Alaska 2012), appeal dismissed (Apr. 6, 2012), citing Park Vill. Apartment Tenants Ass'n v. Mortimer Howard Trust, 636 F.3d 1150, 1160 (9th Cir. 2011).* An administrative agency may not impose sanctions that are unwarranted in law or without justification in fact. *Am. Power & Light Co. v. Sec. & Exch. Comm'n, 329 U.S. 90, 112-13 (1946); Syverson v. U.S. Dep't of Agric., 601 F.3d 793, 800 (8th Cir. 2010).* Accordingly, the PCO requirements constitute an abuse of agency discretion and are potentially subject to judicial review under the APA.

As made evident in this brief, EMPCo recognizes that the IMP rules intend that both industry and the Agency learn from incidents as part of the process of continual evaluation, regardless of whether violations of the rules occurred. The Company has already begun a review of its IMP program and procedures in light of the Pegasus incident, and it intends to continue that review and revision even before a Final Order issues in this case (at which time any proposed Compliance Order would take effect). The ongoing review that is being undertaken by the Company is expected to fully address the terms of the PCO (including Paragraph 1), but the Company respectfully reserves its objections as stated.

VII. SUMMARY AND RELIEF REQUESTED

It is clear that PHMSA issued this NOPV solely because a high profile incident occurred. EMPCo does not minimize the significance of the incident; the Company has assumed responsibility for it, and continues to work with numerous parties to resolve all issues resulting from the event. The Company does challenge the Agency's enforcement response, however. The Agency inspected the Company's IMP program several times prior to the incident, and found no violations related to the allegations in this NOPV. But once the incident occurred, the Agency presumed that there must have been violations of the Part 195 regulations, and the IMP rule specifically. That approach, and presumption, is not authorized by the PSA.

[24] Paragraph 1 relates to Item 1 of the NOPV; Paragraph 2 relates to Item 2; Paragraphs 3, 4 and 5 of the PCO relate to Items 5 and 6 of the NOPV; Paragraphs 6 and 7 of the PCO relate to Item 8 of the NOPV; Paragraph 8 relates to Items 3 through 7 of the NOPV, regarding documentation; and Paragraph 9 of the PCO is a non-mandatory request for retention of cost records.

No Strict Liability under the PSA

There is no strict liability provision in the Pipeline Safety Act to establish liability without fault or causation. The Agency must prove that violations occurred, not simply that an accident occurred. Although the Agency may be reluctant to acknowledge this, accidents can occur even when an operator is in full compliance with the rules. This is one such accident. Even though the Company was in compliance with the IMP rules in this instance, and no actionable anomaly was reported by state of the art inspection tools at the point of rupture, the accident nonetheless occurred.

EMPCo Complied with Applicable IMP Regulations

The core of the Agency's allegations in the NOPV is that EMPCo failed to *conclude* that the pipe segment in issue was susceptible to seam failure. Hindsight is indeed perfect, but the IMP regulations only require that an operator *consider* the risk of seam failure on LF-ERW pipe, not automatically conclude it. EMPCo did carefully consider the risk of seam failure on this segment. The Company reviewed the issue multiple times over several years, and documented its compliance with the rules on every occasion.

If the Agency's core allegation regarding seam failure susceptibility is incorrect, then Items 1 through 4 of the NOPV, at a minimum, fail to state a claim. If the Agency's core allegation is upheld, however, then the entire industry and the public must now reconsider the Agency's rules and precedent regarding LF-ERW pipe. Nearly one quarter of all oil pipelines in the U.S. contain LF-ERW pipe. If operators must now conclude that such pipe is automatically susceptible to seam failure – without allowing for the evaluation and consideration process set forth in the rules and used by all parties up to now – then the time and cost to implement that conclusion could affect energy supplies throughout the U.S. Moreover, such a sweeping characterization would undermine the public's faith in PHMSA's ability to monitor pipeline integrity and safety in a logical and consistent, rather than a purely reactive manner.

As with most activities, it is not possible to predict and prevent all accidents. The Pipeline Safety Act, and PHMSA regulations, establish a framework that requires careful identification of threats, analysis of those threats, inspection methods designed to find problems before they become manifest, and strategies to reduce and mitigate risks. That system has worked, as made evident by the continually declining number and size of pipeline incidents over the past twenty years.

Despite the success of the Agency's pipeline integrity management program, some accidents can occur even when an operator is in full compliance with the rules. In this instance, the Company not only complied with the IMP rules, it did more than what was minimally required. Nationally recognized experts (relied upon by PHMSA even in this proceeding) consulted with EMPCo on its compliance with IMP rules before this incident occurred and their affidavits in this matter lend strong support to the Company's arguments. Even though the pipe was not deemed susceptible to seam failure, the Company voluntarily ran the same tools and took the same risk reduction methods beyond those required under the regulations. Significantly, an ILI seam tool did not report any actionable anomaly at the point of rupture before the incident occurred. That fact alone undercuts all of the government's assertions in the NOPV.

Neither a Penalty nor the PCO is Warranted

If the basic premise of the NOPV is wrong, then there is obviously no basis to assess any administrative penalties against the Company. Even if the Agency's alleged violations are upheld, the penalty should be adjusted downward. Items 1 through 4 of the NOPV are so closely related as to constitute a single violation, subject to a $1 million penalty cap. The other alleged violations also depend on erroneous presumptions, not supported by the record. Instead of applying mitigation factors in light of the Company's cooperation, the NOPV erroneously asserts that the Company made a conscious decision not to comply with the law, even while the Company did more than the minimum required.

Similarly, if the substantive allegations of the NOPV are unfounded, then there is no basis for a Proposed Compliance Order (PCO). The Company objects to the scope of the PCO, which purports to apply to "all assets" of the Company, rather than just the pipeline at issue. That is unusual, and unlawful. The Company contests that overly broad aspect of the PCO, but the Company is also already pursuing the elements of the PCO, as it is EMPCo's understanding that the IMP rules properly read require continual evaluation and improvement, regardless of any PCO. The public and the industry would be well served if the Agency used its resources to learn from this incident, rather than to deflect concerns about application of rules, guidance and available technology.

For all of these reasons, EMPCo respectfully requests that the NOPV be withdrawn, or significantly revised in accord with applicable law and precedent.

Respectfully submitted,

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Date: June 2, 2014

<u>**Index of Attached Exhibits**</u>

No.	Exhibit
1	Affidavit of John Kiefner (5/22/14)
2	Affidavit of Kent Muhlbauer (5/31/14)
3	M. Baker, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Chapter 4 & Figure 4.1 (April 2004)
4	EMPCo IMP Manual Excerpts, Sections 4.4, 5.1(4), 5.4 (2012)
5	EMPCo OIMS Framework, Elements 2.4; 7.2 (2009)
6	EMPCo OIMS System 2A, Attachment #1 Risk Matrix Methodology (rev'd 2004)
7	EMPCo TIARA Manual, Section 8.0 (2007)
8	EMPCo Memo regarding Corsicana to Patoka LSFSA (12/10/04)
9	EMPCo Memo regarding Corsicana to Patoka LSFSA (2/10/05)
10	EMPCo Management of Change Form No. 05-2829 (8/10/05)
11	EMPCo Management of Change Form No. 05-2833 (8/10/05)
12	EMPCo Hurst Metallurgical Analysis of Hydrotest Failures Excerpt Report No. 51708 (6/21/06)
13	EMPCo TIARA Foreman to Conway UDT Q&A (6/26/06)
14	EMPCo Corsicana to Patoka Summary of Hydrotest Learnings (7/06/06)
15	EMPCo Hurst Metallurgical Analysis of Hydrotest Failures Excerpt Report No. 51763 (7/06/06)
16	EMPCo IMP Integrity Assessment Data (IAD) Form 3.2 Foreman to Conway (7/26/06)
17	EMPCo TIARA Foreman to Conway Manufacturing Threat Classification (7/26/06)
18	EMPCo TIARA Foreman to Conway Risk Assessment Summary (7/27/06)
19	EMPCo Risk Assessment Summaries: Corsicana to Foreman, Conway to Doniphan, Doniphan to Patoka (2006/2007)
20	EMPCo IMP Preventive & Mitigative Actions (P&M) Form 6.1, Foreman to Conway (2007)
21	EMPCo Foreman to Conway LSFSA and Pipelife Analysis Excerpts (2007)
22	EMPCo Patoka to Corsicana LFSA Review (2009)
23	EMPCo Email from NDT (8/23/10)

No.	Exhibit
24	EMPCo NDT Preliminary ILI Report Conway to Corsicana (received 8/23/10)
25	EMPCo Repair Form PL-0751 MP 164.05 (8/28/10)
26	EMPCo IMP Exception Form 1.2 (12/17/10)
27	EMPCo Final NDT ILI Report & Repair Summary Conway to Corsicana Excerpts (2011)
28	EMPCo TIARA UDT Q&A Conway to Corsicana (2011)
29	EMPCo Conway to Corsicana LSFSA and Pipelife Excerpts (2011)
30	EMPCo Email from NDT & MP 142.39 Dig Sheet (1/10/11)
31	EMPCo Repair Form PL-0751 MP 142.39 (1/12/11)
32	EMPCo Repair Form PL-0751 MP 274.09 (1/13/11)
33	EMPCo IMP Exception Form 1.2 (1/31/11)
34	EMPCo Conway to Corsicana Manufacturing Threat Classification (3/4/11)
35	EMPCo Conway to Coriscana IMP Form 3.2 IAD Form (3/15/11)
36	EMPCo Conway to Corsicana P&M Form 6.1 (7/21/11)
37	EMPCo Conway to Corsicana EFRD Form 6.2 (7/21/11)
38	EMPCo IMP Exception Form 1.2 (8/02/13)
39	EMPCo IMP Exception Form 1.2 (8/28/13)

Index of Exhibits Included by Reference Only

No.	Exhibit
40	EMPCo Patoka to Corsicana 2005/2006 Hydrostatic Test Reports (MP 127-437)
41	EMPCo Metallurgical Analysis performed by Hurst Report No. 40912-F (12/19/05)
42	EMPCo LSFSA Foreman to Conway and Pipelife Analysis (2006)
43	EMPCo Metallurgical Analysis performed by Hurst Report No. 41305 (4/20/06)
44	EMPCo Metallurgical Analysis performed by Hurst, Report No. 41500 (4/24/06)
45	EMPCo Metallurgical Analysis performed by Hurst Report No. 51695 (6/17/06)
46	EMPCo Metallurgical Analysis performed by Hurst Report No. 51708 (6/21/06)
47	EMPCo Metallurgical Analysis performed by Hurst Report No. 51763 (7/6/06)
48	EMPCo TIARA Foreman to Conway Risk Assessment (7/27/06)
49	EMPCo TIARA Manual (2007)
50	EMPCo Conway to Corsicana NDT MFL Combo ILI Final Report (2010)
51	EMPCo Patoka to Conway GE PII TFI Final Report (2010)
52	EMPCo LSFSA Conway to Corsicana and Pipelife Analysis (2011)
53	EMPCO IMP Manual (2012)
54	EMPCo Conway to Corsicana GE PII TFI Final Report (2013)
55	Hurst Metallurgical Investigation of Pegasus Pipeline Report No. 64961 MP 314 (7/9/13)
56	EMPCo Pegasus Root Cause Failure Analysis Final Report & Appendices (3/26,/14)

Hearing Sign-In Sheet

ExxonMobil Pipeline Company
CPF 4-2013-5027
June 11, 2014
Houston, TX

Name	Title	Organization
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BOB HOGFOSS	" "	" "
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JOHNIE RANDOLPH	COUNSEL	EMPCo
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Molly ATKINS	Accident Investigator	PHMSA
LARRY WHITE	OPS COUNSEL	PHMSA

Name	Title	Organization
CLIFF ZIMMERMAN	COMPLIANCE OFFICER	PHMSA
Rod Seeley	Director	PHMSA

BEFORE THE
U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY

IN THE MATTER OF	)	
	)	
EXXONMOBIL PIPELINE COMPANY	)	CPF NO. 4-2013-5027
PEGASUS PIPELINE INCIDENT	)	NOTICE OF PROBABLE
(MARCH 29, 2013)	)	VIOLATION
MAYFLOWER, ARKANSAS	)	

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PHMSA HEARING

June 11, 2014

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PHMSA HEARING was taken in the above-styled and numbered cause on June 11, 2014, from 8:27 a.m. to 12:19 p.m. before Roxanne K. Smith, Certified Shorthand Reporter in and for the State of Texas, reported by computerized stenotype machine at 8701 South Gessner, Suite 1110, Houston, Texas.

A P P E A R A N C E S

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A P P E A R A N C E S

(continued)

ALSO PRESENT:

PHMSA:

Ms. Molly Atkins, OPS Inspector, Accident Coordinator for PHMSA Southwest Region
Ms. Mary McDaniel, Operations Supervisor for PHMSA Southwest Region
Mr. Larry White, Counsel, PHMSA Headquarters
Mr. Cliff Zimmerman, Compliance Officer, PHMSA Headquarters (VIA TELEPHONE)

ExxonMobil:

Mr. Troy Cotton, EMPCo, General Counsel
Mr. Johnnie Randolph, EMPCo Counsel
Ms. Johnita D. Jones, EMPCo Pipeline Risk and Integrity Manager, Operations Department
Mr. Steve Koetting, P.E., Engineering Specialist, Pipeline Integrity

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INDEX

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(Proceedings commence at 8:27 a.m.)

THE HEARING OFFICER: Good morning. Thank you-all for attending. This is the informal hearing concerning the Notice of Probable Violation issued by the Office of Pipeline Safety Southwest Region to ExxonMobil Pipeline Company. The issue was issued November 6th, 2013. The CPF number is 4-2013-5027.

The notice alleged nine violations of the pipeline safety regulations, proposed civil penalties of approximately $2.6 million and proposed a compliance order.

My name is Ben Fred. I'm the presiding official at today's hearing. I'm an attorney in PHMSA's Office of Chief Counsel. I am the designated presiding official for pipeline safety enforcement hearings.

I'll give some brief remarks about how today's hearing will transpire and how the case will proceed after today's hearing. But first, let's begin with a round of introductions. We'll start over here.

MS. LITTLE: Sure. Catherine Little, counsel with ExxonMobil Pipeline Company with Hunton & Williams law firm.

MR. HOGFOSS: Bob Hogfoss, Hunton & Williams law firm for ExxonMobil.

MR. KOETTING: Steve Koetting, pipeline

integrity specialist for ExxonMobil Pipeline.

MS. JONES: Johnita Jones, risk and integrity manager for ExxonMobil Pipeline Company.

MR. RANDOLPH: Johnnie Randolph, counsel for ExxonMobil Pipeline Company.

MR. COTTON: Troy Cotton, general counsel for ExxonMobil Pipeline Company.

MS. MCDANIEL: Mary McDaniel, operations supervisor, PHMSA.

MS. ATKINS: Molly Atkins, accident investigator, PHMSA.

MR. WHITE: Larry White, serving as OPS counsel.

MR. SEELEY: Rod Seeley, director for PHMSA Southwest Region.

THE HEARING OFFICER: And Cliff, can you introduce yourself?

MR. ZIMMERMAN: Cliff Zimmerman, compliance officer at headquarters.

MR. WHITE: I'll sign in for Cliff.

THE HEARING OFFICER: Thank you. Now, some brief procedural remarks, PHMSA's regulations authorized this hearing and specified the manner in which it will be conducted. Those regulations are in 49 C.F.R. Section 190.211.

Today's hearing will be conducted informally, which means we'll not be required to follow any specific rules of evidence or rules of procedure. Each party will have time to speak without interruption to make sure that we give each side enough time to cover everything that they'd like to present. And then at the appropriate point, we can engage in some back-and-forth discussion.

This hearing is being recorded and will be transcribed for the record. You will note that I'll also be taking notes during today's hearing. My notes are for my use later on in the case, which I'll get to in a second. My notes are not made a part of the official record.

As the presiding official, my role is two-fold. First, I'll regulate the course of the hearing today to make sure we cover everything in a fair and efficient manner. I'll also be listening to the positions of the parties today in anticipation of preparing a recommended decision in this case. So, my second role is after the hearing is over and after any additional materials are submitted to me, I'll be preparing a recommended decision in the case, which is forwarded to the Associate Administrator for Pipeline Safety who will issue the Agency's decision called a

final order.

The final order will make findings as to whether each of the alleged violations were proved; and if so, will specify the terms of any civil penalty and/or corrective action. Under our procedural regulations, the Regional Director will be submitting a post-hearing recommendation to me. I'm not bound by the Region's recommendation. I'll consider everything stated here today impartially, as well as everything submitted in written materials when I prepare my independent recommended decision.

Upon issuance of the final order, our regulations permit the Respondent to petition for reconsideration of the final order within 20 days of receipt, and that's provided for in 49 C.F.R. Section 190.243. So, that's how the hearing will be conducted today and how the case will proceed after today's hearing.

Some quick housekeeping matters. We're getting started right on time at 8:30. So, we'll plan for a break at 10:00 o'clock or so; but that's flexible depending on how things are going. And then we'll also have a break for lunch. I will -- we will -- the hearing today will last as long as it needs to to make sure we cover everything, but usually I ask in the

beginning if anyone has any afternoon travel plans that we should try to meet or if people's schedules are open. Okay.

Finally, Mr. Seeley, it's your turn to let everyone know where the facilities are and emergency exits.

MR. SEELEY: For those who are not familiar with us, for the facilities, the restrooms, if you go out our main entrance, if you take a left, they're down the hallway. In the case of an emergency where we have to evacuate the building, the stairwell is just beyond the restrooms. We would take that stairwell down to the first floor, exit the building and head down. Best thing is just to follow us since you don't know where we'll be going. But we'd go down to the street and congregate at one of the corners.

There is a break room down on the first floor. You have to go out security, and they have snacks and sodas and whatnot. We have a water bubbler in our little kitchen there. I don't know if there's coffee there because I don't drink coffee, but they have all your snacks and drinks downstairs if you want.

THE HEARING OFFICER: Okay. Thanks.

Has everyone signed in? Great. Before we

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get started, does anyone have any opening remarks before we start talking about the individual items?

MR. SEELEY: We do not.

THE HEARING OFFICER: Okay. Did you have a preference on the order in which you wanted to cover the items?

MR. HOGFOSS: Well, actually, we were going to suggest that after PHMSA makes its opening remarks and we do a very short version of ours, that in the interest of time efficiency, since the first issue of the nine and really Items 1 through 4 will likely engender the most of the discussion, we thought perhaps if the Region agrees, we could talk first about Items 5 through 9.

And then on all of the items, again just to make this as productive as possible, we thought we will state, you know, our position on an item and then encourage the Region to actually discuss it item-by-item instead of coming back, because we may all have forgotten some of the things we've said by the time we get through all of the nine.

THE HEARING OFFICER: Okay. So, if I understand, you wanted to talk about 5 through 9 individually.

MR. HOGFOSS: Yes.

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THE HEARING OFFICER: And then --

MR. HOGFOSS: And then 1 through 4 individually.

THE HEARING OFFICER: Okay.

MR. HOGFOSS: And then I guess we conclude with just some comments on penalties but at each point. Instead of making one very long essentially opening statement, we thought we can just go item-by-item.

THE HEARING OFFICER: Okay. I don't have a problem with that. Start through items 5 through 9?

MR. SEELEY: That's fine.

THE HEARING OFFICER: Okay. Would the Region care to introduce Item 5?

MR. SEELEY: Yeah. I'll briefly introduce it. I'm not going to present all of the evidence and the stuff that's already been submitted to the case file and to the violation report.

But Item 5 of the notice relates to the operator failing to take prompt action to address anomalous conditions on the pipeline. This has to do with some ILI runs where there were some immediate conditions identified. And through our investigation and review of records, it -- the records did not indicate that the prompt action required an immediate

condition was taken.

THE HEARING OFFICER: Thank you. Okay?

MR. HOGFOSS: Would you like us -- well, to begin with, just on behalf of ExxonMobil Pipeline Company, we do thank all of you for coming, especially Ben and Larry who traveled. And we would like to note at the outset that the Company understands this was a very significant incident. The Company took full responsibility for the incident from the outset, has cooperated with the Agency, with many agencies, continues to cooperate, continues to work with the federal government, the state government and many other parties.

And the Company does not see this matter, the PHMSA administrative violations, as much of a monetary penalty issue as a larger question about how the integrity management program rules, the IMP rules, really are intended to apply. And so, that's -- that's the theme that you have seen in our pre-hearing materials and you'll hear again today. But we do thank you for attending this hearing and engaging on these issues.

So, to -- and I guess a final thing just to note is that these are -- and we noted this in our pre-hearing materials -- these are legal issues. The

nine items are alleged violations of PHMSA's regulations and/or the Company's IMP procedures, which have the force of regulation. So, they're legal issues. It's a very complex factual record that the Region knows well, and the issues are known well to both the Agency and the industry.

But ultimately what we're looking at is that the Agency has made alleged violations. The burden is on the Agency to establish those violations; and our responsibility is, where appropriate, to challenge the elements of the claim to see if they're met. So, that's our focus; and we will try to be as efficient as we can.

As to Item 5, we think this one is really an issue where the allegations are simply incorrect, that you just looked at the wrong data. The allegation, as Rod said, was that on two occasions at two different mile markers, the Agency [sic] failed to declare a discovery. They failed to identify an anomaly from an in-line inspection tool that needed some type of repair in a timely manner in accordance with the IMP regulations. We should note that both of these two items called out were a long way away from the Mayflower incident itself.

So, this is really more about how the IMP program works. Both of these cases we think if you look

at the actual record -- and correct it -- and we understand when you're putting together the NOPV, you don't have as much time to look at all of the data as you may have later. And so, the passage of time helps inform [sic] some of this. But in both cases, these two -- these two anomalies were actually classified properly within two days of receipt of information, and they were both repaired within five days. So, let's go through both of them.

The first one was at milepost 164.051. It was reported to the Company in a preliminary report. So, the IMP rules allow 180 days from the completion of the tool run to declare discovery where practicable, the rule says. In this case, they did get a preliminary report on August 23, 2010 -- and that's shown in materials in Exhibits 23 and 24 -- and it was shown to be a 72 percent wall loss. Well, the irony here -- and you can look at Exhibit 25 -- is that the Company declared it an immediate repair anomaly the same day that it received the information and repaired it five days later.

So, we think if you look at Exhibits 23, 24, 25, you'll see that for milepost 164.051, that, in fact, the Company did timely declare discovery, did promptly act on it; and we think that should be

withdrawn.

MS. LITTLE: And the confusion I think that was presented in the NOPV is there's a document that is a vendor document, not a document that was dated with a vendor date, not the date that the preliminary report was provided to ExxonMobil Pipeline. That is the August 9th date that was included in the NOPV. But if you even look at the next NOPV item number, Number 6, it notes the date the preliminary report was received, which is the date that ExxonMobil received that information, which is the August 23rd date that Bob just referenced.

MR. HOGFOSS: So, actually the NOPV itself corrects itself. And Item 6, it does show the proper date; whereas, Item 5, the allegation there. And as Catherine said, you know, we can understand how the wrong date was transposed. But I think in looking at the NOPV's own table on Item 6 and then looking at the exhibits we referenced, this should make clear that this one actually was both identified and properly classified and repaired in a prompt manner.

So, the second item alleged in -- the second example alleged in Item 5 was milepost 142.394. And that one was not called out in a preliminary report, but it was only noted for the Company in the final

report that is received from the vendor. And you can see that in Exhibit 30 of our materials. It was received on January 10, 2010. It was really a much less of an anomaly. It was a 0.74 percent top dent with a corrosion pit.

The anomaly was repaired two days later on January 12th. That's shown in Exhibit 31. Again, here in the Pipeline Safety Violation Report, there are documents cited regarding a different anomaly than alleged in the NOPV; and you can see that in Exhibit 32. The other -- the Exhibit 23 anomaly is a different milepost, and that one was an immediate repair. That information was received on January 10 and repaired on January 13th.

So, at bottom, we're saying that both of these, we think it was just a mistake of fact in terms of looking at them and thinking that they were not properly and timely classified when, in fact, we think that the record shows that they should be corrected.

Any other comments from our side? Is it okay if we -- I mean, we're okay to just discuss this now. Or, Rod, if you want to wait; and we can come back.

THE HEARING OFFICER: Do you have any comment on --

MR. SEELEY: This seems to be -- we don't want to get confused with the discovery versus the action. This is more of the action on the anomaly. And it seems to be a controversy, if you will, over reports and dates; and I will turn to Molly to discuss her records and what she reviewed, where she got her dates from, compare and see where the differences are.

MS. ATKINS: The primary information that we looked at that caused us to ask questions was the repair reports, and the discovery date and repair date through most of the reporting were the same or one day apart. So, while the discovery may be somewhere else, the records we have, for example, in your Exhibit 25 on the third page, it says discovery was 8/27 and repair was 8/28.

The information that we relied upon is the preliminary report. Initially we had the date of 8/23 as being received; but when we requested a copy of the preliminary report, it had the date on it of August 9th, I believe --

MS. LITTLE: And, again, I think --

MS. ATKINS: -- the vendor date.

MS. LITTLE: It was a vendor date in the underlying document of the vendor -- their date. That wasn't the date received by the Company.

MS. ATKINS: So, when we looked at the e-mail in Exhibit 23 of your brief, the e-mail states, "Today is the day he wanted them sent to him." Our experience has been normally the information is available and shared over the telephone or at some point in the process as soon as the vendor has it and has that information. And while it was 72 percent, it said it was affected by pressure and it was less than a pressure [sic] of one.

So, the information that we have was not so much the determination or classification as immediate; but it is those other actions that must be taken, such as a pressure reduction or a shutdown until the repair can be made. And when discovery is declared on the same day that the repair is made, it would appear that those actions for pressure reduction or shutdown are not being taken. But at this point, we have no information as to whether or not a pressure reduction was taken.

So, without any other information other than the records to rely upon, it would appear that for discovery and repair to occur on the same date and different than the dates of the information being available to the Company, that the response actions are not just classifying it; but it is to take that

immediate pressure reduction or shutdown until the repair is made.

MR. HOGFOSS: If I could just ask two questions. So, the exhibits we pointed out, I think we noted where we see some discrepancies could have come in, some misreading of it that you don't see the points that we're making.

I guess my question is, Catherine said the August 9th date was a vendor date. And vendors in the real world do not actually provide all of the information; and it is a major issue for both the Agency and the industry if you don't necessarily get all of your information on time. In fact, if you look at -- it's worth looking at Exhibit 30, just as an example; and it's a series of e-mails.

And look at the third page in Exhibit 30 near the bottom, and there's an exchange there with an EMPCo representative sending a pretty strongly worded message back to an ILI vendor saying, Look, you just gave us a final report and for the first time called out some immediate repairs. And we are not at all pleased with this. This is not what we expect. And it carries on in the next paragraph to say this is simply not -- you know, we do not like surprises like this.

That's just an example of how it actually

occurs, that there is frustration. There is a vendor issue, frankly, with they -- you know, the way it's supposed to go. And Steve or Johnita can address this better than I can. But the way it's supposed to go, as you know, the Agency expects is an ILI tool vendor, as they're getting their data and should be looking and letting their company know when to work on immediate repairs. It usually goes that way. It doesn't always go that way.

And then also the rules require that, you know, you give 180 days to find this. Vendors don't always get their reports to companies within 180 days, which is why the rule which we can remember personally from when the IMP rules came out, that the comments and the discussion at the time, there was concern back in 2000, 2001, [sic] were there enough ILI tools out there to implement IMP.

I think that's progressed to 12 years later from the effective date of the rule to there's not that many vendors, and they are very difficult contractually to try and force -- frankly, ultimately, this is beyond the issues in this hearing -- but it would be helpful if the Agency could promulgate some rules that apply to vendors to be more prompt. But that's an example of -- in response to your comment that

what we see as the Company -- when the Company gets the information, they act on it.

MS. ATKINS: We don't take any exception to immediates being identified in a final report. We understand the correlation with the metal loss tools has to occur and that usually occurs after the preliminary report with the analyst being able to correlate the two runs.

But the issue is that the date of the repair in your exhibit shows discovery and repair on the 6th, which is before the final report is stated to be received. So, again, it may be a record-keeping issue; but the records that we had to rely upon show repair that in your tab -- and, again, it was 31 labeled on January 12th. Let me find that exhibit -- it shows on Page 3 that the repair and discovery for January 6th. And you state that the final report was received on the 10th. So, those dates don't match. The Exhibit 31 and Page 3 of that exhibit actually shows discovery date of 1/5 and repair date of 1/5. Yet, the front page has a date of 1/12, where the number of five has been scratched out and amended.

The other one which may have been the immediate, which is under Tab 32, is the one that shows discovery and repair 1/6.

MR. HOGFOSS: The Exhibit 32 is the -- that's where the violation report --

MS. ATKINS: Uh-huh.

MR. HOGFOSS: That's the wrong anomaly. We were pointing that out. That's at a different milepost. That's at 274.091.

MS. ATKINS: It was the intent that be the anomaly. In either case, they both show the 1/6 and 1/5 discovery and repair.

MR. HOGFOSS: Again, we're just going back to the NOPV. What's written in the NOPV were these two mile markers. And as we were trying to understand the basis for the alleged violation, we noted that there was this confusion of different mile markers. And so, if you're now saying the intent was this other mile marker in Exhibit 32, then, in fact, that was also timely classified and repaired.

MS. ATKINS: Yes. I think my point was the date of discovery and repair are the same but prior to receipt of the final report on the 10th. And for discovery and repair to occur on the same day, you're declaring discovery in the ditch, not --

MR. KOETTING: In some cases we do.

MS. ATKINS: -- prior to that.

MR. KOETTING: In some cases we do.

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MS. ATKINS: So, you have information ahead of time that caused you to call this an immediate. So, the response is to take an immediate pressure reduction or shut down the pipeline for immediate conditions. So, at what point are you saying that it was determined it was immediate? For those two dates to coincide means it's being declared immediate in the ditch, not in the office. So, you're not using the reports to qualify it as an immediate and take those actions.

So, the actions that we expect for immediates is that you receive the information. You make a determination about it meeting criteria for immediate or not. And then they go out and do the examination. And that immediate triggers additional actions prior to, as in your procedures say that you must take immediate pressure reduction.

So, in the code and in the procedures, that is the expectation for an immediate condition.

MS. LITTLE: Let's go back.

MS. ATKINS: And that's the part that I can't find. If there was, in fact, a pressure reduction taken, maybe you could demonstrate that through a record of a pressure reduction.

MS. LITTLE: The NOPV Item itself, if we

look back at what the allegations are in NOPV Item 5, what you-all note in here is that the operator failed to take prompt action, failed to declare discovery from information received in preliminary reports. And the first example that you use, the 164 -- milepost 164.051 and milepost 142.394, the way in which the allegation reads is that both sites were identified as immediate repairs from the preliminary report that was received on August 9. And then you note that the operator didn't identify them as immediate repairs until the sites were excavated, the first one being 19 days later and the second one being several months later. And I think the way in which -- you're speaking just on different issues now in terms of --

MS. ATKINS: The immediate response --

MS. LITTLE: -- what we want to see.

MS. ATKINS: I'm sorry. I didn't mean to interrupt you.

MS. LITTLE: That's okay. No, I'm just -- to bring us back to what the allegation says, when we look at milepost 164.051 -- and I think as the documents we provided demonstrate -- that was not received -- that information, the preliminary report, was not received until August 23rd; and it was declared an immediate on that same day upon receipt of that preliminary report

and repaired five days later. So, that was not declared in the ditch, as you said.

MR. HOGFOSS: So, we have a -- again, as Catherine's saying, we're looking to the alleged violations in the NOPV; and we thought as we looked into this, this just seems clearly to be just a mistake, a transposition of dates, which is understandable given all of this information. So, this -- these two seem to be a simple matter of just correcting and saying, gosh, looking at the right documents --

MR. SEELEY: Just to help me out. We apparently have a record that shows an August 9th date. Your assertion is that that receipt of that report was actually August 23rd.

MS. LITTLE: That's right, and we include the cover letter in our --

MR. HOGFOSS: And the Company provided that letter to you, but it was misconstrued that the Company had possession of that on August 9th.

MR. SEELEY: What is the discrepancy between August 9th? Does an August 9th report exist?

MS. LITTLE: There's a August 9 date on a document that the vendor maintained and was part of the documents that came with the preliminary report. But it is the vendor's August 9 date that refers to something

the vendor was doing on that day. But all of that material was transmitted to the Company on August 23rd. It was --

MS. ATKINS: The transmittal --

MS. LITTLE: -- not transmitted to the Company on August 9th.

MS. ATKINS: The transmittal indicates that that is the date he requested it be delivered to him.

MS. LITTLE: They have to set deadlines. I'm not sure I understand your point.

MS. ATKINS: How can they hold it if it's available prior to that?

MS. LITTLE: I'm not sure it was.

MR. HOGFOSS: Can you point to a document you're talking about? Again, the Company didn't receive it --

MS. ATKINS: It's your transmittal cover letter in the exhibit. And that's the first time I've seen that because I was just provided the report. And so, the transmittal says that is the day that he requested it be sent in the e-mail. So, we go back to that exhibit, Exhibit 23, Page 2, "Here are the preliminary files for the ExxonMobil job. Please forward them to Chris Gorman after your review. Today

is the day he wanted them sent to him."

MS. LITTLE: To me that means the deadline and the date they were expected to be provided. I don't know why that would suggest anything differently.

MR. SEELEY: Okay. So --

MS. LITTLE: It takes them a long time to pull together all the information, we know that, the vendors.

MR. SEELEY: So, your date record which would indicate August 23rd is delivery of the report, you've declared this anomaly to be an immediate; and then your actions were five days later. Did you do any action between the 23rd and the 28th?

MS. LITTLE: Declared it an immediate on that same day. Scheduled and undertook to repair --

MR. SEELEY: So, your immediate --

MS. LITTLE: -- that took place in five days.

MR. SEELEY: -- action was five days later.

MS. LITTLE: The repair was declared immediate.

MR. SEELEY: I asked were there other actions -- I guess maybe I'll rephrase. Were there other actions taken between the 23rd and the 28th where

I'm assuming you made some sort of mechanical fix?

MR. KOETTING: The crews are not located right on the site. We had to scramble.

MR. SEELEY: I'm not talking about mechanical fix. I'm talking about an action. Did you take any other immediate action like a pressure reduction or something that is actionable without a mechanical fix? The repair is a mechanical fix, correct? So, I'm asking: Are there other actions that the operator took between those two dates?

MS. JONES: Our program makes an analogy between an unvalidated preliminary report and an immediate repair and a safety related condition. So, we have five days to validate that report and then five days to fix it. And so, we immediately convene a discussion internally when we receive that report and begin to take those steps as if it were a safety condition. So, we repaired it within that very first five days.

MS. ATKINS: So, the record shows here the discovery date of 8/27 and repair date of 8/28. But you're saying the discovery and declared an immediate was the 23rd?

MS. JONES: Yes.

MR. KOETTING: This is a 72 percent. We

had a tool tolerance to determine that it was possibly -- we've been criticized for that. This particular case, we don't know if it's --

THE HEARING OFFICER: Can you speak up just a tad?

MR. KOETTING: The anomaly was called out by the vendor 72 percent. On its face, that is not an immediate.

MS. ATKINS: What was the actual?

MR. KOETTING: The actual is 90 percent.

MS. ATKINS: Okay.

MR. KOETTING: So, going beyond what the regulation required by adding tool tolerance to it. We've been criticized for this before. You guys are declaring immediates because you're adding tool tolerance to anomalies. In this case it turned out we did it properly. We excavated and got people out there and it, in fact, it did turn out to be greater than 90 percent. So, there's always this confusion about is it immediate with the call or is it immediate when we actually determine it's immediate? Because if we dug it up and it was actually 60 percent, that's not an immediate.

So, this whole point of discovery has to do with what does it actually turn out to be. So, in

this case, it did turn out to be immediate. Thank goodness that we acted on a preliminary report that showed it less than that. I think we took prompt action.

MR. SEELEY: I don't think we have any other unique points to make.

MS. ATKINS: What we were looking for is the action until the repair was made, which is what code states, a pressure reduction or shut down for immediates until the repair can be made. And so, that may be something we need to look at the procedure and see what your procedure at that time said because it has changed since that time frame. I know that immediate response is different today than it was in 2010.

MS. JONES: And that procedure has been looked at numerous times.

MR. HOGFOSS: We won't -- so much for trying to be time efficient. It's only Number 5. We won't belabor this, but what we'll say for a wrap on this one, is that the allegations in Item 5, when we look to them, we see that they're incorrect. They don't match the actual record in terms of dates and mileposts. And as Steve just said in terms of this first example given, it actually did not meet in the preliminary report criteria in the rules for an immediate. So, you

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know, we can address that in our post-hearing submittal. But clearly I guess we leave this one unresolved.

Now, to --

MR. WHITE: Can I make one last point on Item 5 before we move to the next one?

THE HEARING OFFICER: Were you done?

MR. HOGFOSS: No. I was going to say we're ready to move on to Item 6.

MR. WHITE: I just want to say that I can understand that the 23rd -- taking the 23rd as the day that the repair was done five days later and the regulation calls for immediate action. And so -- but I just want to point out that, you know, this -- this case, it happened to be five days. But, you know, the next time it might be 10 days. The next time it might be 15, 20 days.

I mean, we have to -- we have to -- the concern, I guess, for the Agency would be it can be a sort of slippery slope. And so, I think what these folks, when they come into that situation as we've got a preliminary report calling something out as immediate, is start looking -- they're looking for immediate action. So, I can understand why the allegation was brought. I can understand why the Company feels that it did take prompt action. But I just simply say that, you

know, we -- I think the Agency has to worry a little bit about -- you know, we don't want to get into sort of a line drawing exercise here. But I think that's sort of the reason why the inspectors were sort of -- this would catch their attention.

MR. HOGFOSS: And this is a term that we will discuss often today. But hindsight is perfect, and this is a minor example of it, that, yes, knowing what you know once it was dug and examined, it was an immediate. The preliminary report didn't classify it as an immediate. So, the Company treated it as that. And so, that's another postscript. You have to deal with -- all of us have to deal with the facts presented the way they are.

But we are ready for Item 6 if you want.

THE HEARING OFFICER: Okay. Item 6.

MR. SEELEY: Item 6 has to do with declaring discovery within the 180-day time frame. There is a table in there -- I'm not going to go through it -- where it points out several ILI runs and it articulates the 180-day deadline. And the records that we reviewed, we list their dates of discovery from what we can tell. And they all exceed the 180-day requirement that was in the regulation.

THE HEARING OFFICER: Thank you.

MS. LITTLE: Okay. Back to discovery for this one as well. Just as you said the Item 6 cites to four different occasions where the Agency believes that the Company failed to declare discovery. And I think, as we've demonstrated in the brief -- and we can talk about here -- in each one of those instances, the ILI data wasn't received from the vendor until very nearly the end of the 180-day period from when the pig hit the trap. In one case I think it even was provided after, I think in one instance.

So, in all of those cases -- and the regs allow for a company to claim that a period is impracticable in certain instances to meet the 180-day time period. When you don't get the vendor data until nearly the end of the 180-day period and you still have to verify that data and allow time for data integration to make sure you've got good data and make the judgment calls you need to make as an operator.

It's simply not possible when you have a negative time frame because the data came after the discovery or you're in a very tight time frame. The IMP rules and procedures that the Company has in place under IMP allow for that, there's a process that's set forth that the Company follows as to when you can say something is impracticable. And in each of those cases,

you know, they looked and followed the rules, the regulations that the Agency had promulgated. They followed their own procedure and revised the discovery deadline as a result of the fact they could not complete the tasks that were necessary to complete within the time frame.

We put in our brief a figure, Figure 4, that shows the dates that the final report was received when the 180-day deadline was originally to run and when the deadline was revised. And in each instance, the -- it shows final report as being very near the deadline. So, I think the Patoka to Conway MFL-Combo tool, and TFI tool -- the tool run was completed on August 15th. And the final report was not received until the very end of December in 2010. And they requested an extension in order to be able to do the data integration and do the verification of the data. So, they extended discovery from I think originally -- the 180-day deadline was supposed to be February 11th, and they extended it to March 11th.

For the Conway to Corsicana section, the MFL-combo tool which completed its run on July 21st, the final report was not received until January 7th, 2011 and the 180-day deadline was ten days away. So, they extended the discovery there for the same reasons and

practicability as allowed for under the rules and procedure until March 17th.

And then lastly, the TFI tool for Conway to Corsicana, that run was completed on February 6th. The date of the final report was August 29th, and that was well after the 180-day deadline of August 5th, 2013. So, again, they extended the period there. In each case, we think they followed the rules and followed the Agency's guidance and followed their own procedure manual.

THE HEARING OFFICER: Thank you.

MR. SEELEY: Well, I guess it comes down to what one would consider impracticable under the regulations, and the regulations are written and interpreted or implied very many ways. One of which has been consistent is you have 180 days which includes the vendor reports to be received. And that's something the operator has to be aware of and take care of, and it's not something you can use as an impracticability issue when the vendor doesn't supply that to you.

Also, what other processes you add to a review also has to be considered in that 180 days. That's been consistently stated from the Agency so you have to include that within your 180-day. So, your process, plus the operator's report, has to be within

the 180 days. That's not something you can use as an impracticability argument from the Agency's perspective.
I think that's what I've heard you say, and we would primarily just disagree with that as being an impracticality argument in this case. There are many different ways you could -- to address it if you have a situation. You can segment your runs differently, probably get your reports out shorter. I don't know how the data process works, but I didn't hear any arguments over the actual dates within the record. Did I hear discrepancy of the dates?
MS. LITTLE: Of the dates that you-all have in there.
MR. SEELEY: We're not arguing over dates at this point. They are what they are. It's a matter of -- I think the argument seems to be stemmed on the impracticability issue?
MR. HOGFOSS: I think that's right. I think on the Figure 4, we did supplement it by showing the actual receipt of the report.
MS. LITTLE: Right.
MR. SEELEY: Is this the preliminary report that's in the table now or is that a different -- so, we have that data in our notice as well.
MR. HOGFOSS: Yes. So, it's not an issue

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of dates. But it is an issue and we do take issue with the concept of the impracticability. Because the reason that was added to the IMP regulation was because of the reality that -- and the Agency does not always tell operators that it's a violation if their vendor gets them the data late.

That's the whole reason the process is in the IMP rules, that exception in the rule; and the other provision in the IMP rules to when you need to make an exception to your IMP program, you need to explain it, document it and have a good reason. In this case, that was done in all four of these instances where the vendor got [sic] the data late. And we already referred to Exhibit 30 which was a contemporaneous showing of where the Company is expressing great displeasure to the vendor for getting them information late, but it happens.

It happens not just with this company but with the industry. And the rules allow for that. They say when that happens, we hope it doesn't happen that often, industry and agency. This is how you should deal with it. Don't make a practice of it. Document it when it does. We think in this case it was provided for in the rules. The Company followed the process, and we think it does meet the exception of the rule.

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MS. LITTLE: Johnita, do you want to talk a little bit about the internal process that you-all go through? It's not an easy process if you want to get the deadline --

MS. JONES: The internal process for an exception to the 180-day requirement requires us to go all the way to the vice president of the Company. We take it that seriously. So, it has to go to actually my boss, the vice president. We ask that the engineer who's doing the analysis to give us plenty of time to have those discussions, and it's not a very last-minute type activity. So, we do recognize, especially in this case when you get the reports very late, it is very difficult to do discovery within that 180-day time frame.

MS. ATKINS: Is that your Form 1.2 MOC?

MS. JONES: It's not the MOC. It should be the exception.

MS. ATKINS: Exception? So, 1.2.

MS. JONES: I can --

(Simultaneous colloquy.)

MS. ATKINS: I'm sorry. I'm just having a hard time myself.

MS. JONES: I call it the exception.

MR. KOETTING: That sounds right.

MS. JONES: There will be an exception for each one of these forms to forward to the manager for approval.

MS. ATKINS: Do you recognize that there are things that the operator can do to cut down that delivery time? And the communications with the vendor indicate that they cannot meet the specification dates because of the size of the runs.

In particular in our violation report, Exhibit C, we have a copy of the communications between Jeff Johnson at PII and Chris Gorman where he states in April of 2012, which is well before the run is performed which began in July 2012 and was completed in February 2013, "Our proposal states 90 days for the first 50 miles, 30 days for every 50 miles thereafter, resulting in 258 days." He told you before the tool run that he couldn't meet discovery.

So, these actions of combining, which we have it on another item to discuss later, we were talking about the length of the segments and management of change impacting things to -- regulatory requirements as well, need to be evaluated. And so, that's a separate item.

But in this particular item, it is not impracticable when something is designed that cannot be

achieved. And when the vendor tells you they can't achieve it ahead of time and you experienced it on repeated occasions, it should be something that you're well aware of for the data analyst time and the amount of anomalies on these lines that they have to evaluate.

So, the careful evaluation that they perform for you does take time and the careful evaluation that you must do to see is it an HCA, is it something that's already been repaired? There's a lot of process that goes on and we recognize that. But 180 days is a safety issue for the freshness of the data to be reviewed that is timely and changes occur that further impact and degrade that anomaly.

MS. LITTLE: I think -- just to respond to that a little bit, I think there are some other issues you've raised that are unrelated to NOPV Item 7 and to keep us focused on NOPV Item 7, which is about the 180-day period.

MR. SEELEY: 6.

MS. LITTLE: I'm sorry. Thank you. NOPV Item 6 -- gosh, feels like we should be on 7. NOPV Item 6.

And I think you were talking about the communications with the vendor. And, remember, the discovery time frame runs from the date that the tool

hits the last trap. So, he may be saying in those e-mails -- and I don't have them in front of me -- but, you know, the point being that discovery runs from when it hits the last trap. So, irrespective of what those e-mails talk about about the length of time, the 180-day period doesn't begin until the tool comes out.

MR. SEELEY: I think the part of the conversation is the operator has some control -- and this goes back to the impracticability claim as well. You have some control over what you're asking someone to do. So, to create a situation where the tool run is significantly long doesn't [sic] allow the meeting of the deadline is in your control where you could have and should have shortened those segments so you could have met the 180-day discovery by all communications we have seen.

If you hadn't combined segments or, in other words, had you kept the segments separated, you could have made the shorter segments meet the deadline as required. But instead, the operator chose to have a longer segment, which made it -- resulted in them not meeting the 180 days. That was totally in the operator and vendor's control and communication.

So, it was a choice to have such a long segment; and that's not an impracticability argument.

That's a business choice.

MS. ATKINS: Further, in this TFI run, the first segment was run in July of 2012; and the completion time for the 180-day clock didn't start until February 6th, which in itself was more than 180 days after the first tool was removed from the trap.

In reviewing the 2012 version of your integrity management program where it says the last tool run of the series of runs is when you start the clock, these runs occurred between July 2012 and February of 2013. Justification should be provided for any separation and tool dates greater than one month. I haven't seen that justification.

But we agree that when it comes out of a trap, that is when the clock starts. And in this particular case, no data was requested from the vendor until all tool runs were completed, which further exacerbated the problem of meeting that time frame in that the 180-day clock started in February, not in July when the tool run was actually completed. Those were spaced over a period of time of July, September and February, which are all more than a month. There were two, I believe, in September because there were four significantly separate tool runs.

And the areas were not rerun. The data

was not recollected, and the data that was used from the initial run in July is what was analyzed later. So, the process of discovery was significantly delayed because the dates shown here of the TFI run when you received the final report August 29, '13 is more than a year after when the tool was removed from the trap.

MR. HOGFOSS: Respond in part to that in something Rod said. I think the Region knows well from industry generally that problems with vendors getting late reports to companies is really not limited to the length of segment. It's an unfortunate fact that -- it's a problem with the industry. We know the Agency sees it occurring. It's not -- it's not as rare as it should be to have problems with getting reports, putting aside, Molly, the issue of when -- what you call a tool run and when it is concluded.

The vendors -- there's two separate issues. One is pressing a vendor to provide at least timely reports of what may be immediate conditions as the run's progressing regardless of segment length, and that is done, and to get a final report in a timely manner. And it's a larger problem -- the allegations in this item for the NOPV, first of all, you have four examples. And this is -- don't have a hundred examples sitting there. And the exhibits show that the Company

was being diligent in pursuing the information.

We think it's frankly a selective use of the Agency of trying to find an instance where you could read in delay [sic] when, in fact, we think that the Company dealt with the reality and problems created by vendors in these situations and acted in accordance with both the IMP rule and its own procedures.

MS. ATKINS: So, if the vendor tells you they can't meet the 180 days prior to performing the inspection, you've got knowledge to deal with ahead of the inspection being performed.

MR. KOETTING: That would be an impracticality.

MR. HOGFOSS: My understanding was the vendors will not tell you that, but they also won't commit to the -- they won't be responsible for failing to meet the 180 days, which frankly is something we need help on.

MS. ATKINS: They told you that in this e-mail. I think that was my point.

MR. SEELEY: I think we've covered all of our --

MR. KOETTING: It's very difficult to make discovery when you haven't received the report.

MS. ATKINS: We agree.

MR. KOETTING: What are we to discover within 180 days? We try very hard to get our reports. Sometimes successful; sometimes not.

MR. SEELEY: I think we've --

MR. KOETTING: That's the definition of impracticability.

MR. SEELEY: I think we've covered all the unique points on this.

MS. ATKINS: Just for your reference, I can provide -- this is our violation report, Exhibit C. It's an April 16th, 2012 e-mail chain between Jeffrey Johnson and Chris Gorman.

MS. JONES: I'm sorry. The date?

MS. ATKINS: April 16th, 2012. And it goes back -- there's several e-mails back and forth that is in our Exhibit C to the violation report.

MS. JONES: I guess the only thing I would add would be from the time frame that we got that e-mail to when we were putting that tool in the line, it is not practical for us to go back and change the segment. So, that would require additional trap installation and modifications out in the field to do that. So, between April 16th when we started the tool runs, that physically cannot be done.

MS. ATKINS: In retrospect, you ran it in

four separate sections, four discrete segments run in that inspection.

MS. JONES: There's one point they're inserted, and one point to take it out.

MS. ATKINS: That's correct. But your records to us and your e-mail -- would you like me to pull that one?

MR. SEELEY: I think we can finish up.

MS. ATKINS: Okay.

MR. SEELEY: I think we've pointed it out.

MS. ATKINS: Okay.

MR. RANDOLPH: And one other point on that, it's important to realize for that 2013 TFI, the line was shut down when the discovery was done. So, you know, the vendor themselves had a lot of attention on this issue because they had been --

MR. SEELEY: The line was shut down for what?

MR. RANDOLPH: They had -- the vendor had actually held the data longer and reanalyzed and reanalyzed because there had been a release.

MS. ATKINS: We did ask for -- we did ask for them to look at additional data and provide preliminary data in that very location. That took away their efforts, but that doesn't take away from that

first segment in July of 2012 that had not had the data looked at that was in the failure section.

THE HEARING OFFICER: Okay. Anything else on Item 6?

MR. HOGFOSS: I think we agree to disagree on that.

THE HEARING OFFICER: Okay. We'll move on to Item 7 then.

MR. SEELEY: Okay. Item 7 is an allegation that the operator failed to follow its own IMP procedures. This has to do with the operator extending the timing of some -- some risk analysis, talks about Section -- or your Section 5.4, which requires risk assessments to be updated as changes occur. And without going into all the details, the allegation is the analysis was delayed, which -- without proper justification and, therefore, you did not follow your procedures.

THE HEARING OFFICER: Thank you.

MR. HOGFOSS: Yes. And as we acknowledge, and we stated before, the IMP regulations do require operators to develop their own procedures to implement the IMP rules. And those procedures, we acknowledge, do require a course of law. So, this is our procedure, IMP Plan Section 5.4 and Operational Integrity Management

Systems (OIMS) Section 2.4 at issue. The footnote here, which we will come back to when we get to Item 1, but the Item 1 of the NOPV alleges, it goes back to that the Company should have concluded that a seam tool was required to have been run.

So, this Item 7 is premised on that assumption. Just to note, we will respond to it now in any event, but it presumes that a tool run, a crack tool run was required. Ironically, the Company did elect to voluntarily run a TFI seam/crack tool.

And so, that's -- this allegation is that you didn't -- you delayed running it when you should have. And because of that delay, you didn't update your risk assessment which led to a failure to consider preventive and mitigative, P&M measures. So, we disagree with this on two levels. One is that we don't believe that a tool run was required, a crack tool; and we'll come back to that.

But the Company actually did revise its risk assessment in March of 2011. It was scheduled to be reviewed again in 2013, which is a conservative reassessment interval. There had been no changes that would occur that would affect the risk assessment in this time; and most significantly the tool -- the seam/crack tool was run. Unfortunately for all parties,

it didn't detect a reportable anomaly.

So, our position actually is that the Company exceeded part 195 IMP rule requirements here by voluntarily running a crack tool. It clearly didn't violate those requirements. And ultimately there's some simple logic that kind of undercuts the allegations of Item 7, which is this, is that when the crack tool was run, allegedly late, but when it was run in 2012, 2013 there was no actionable anomaly found at the point of rupture. Because crack growth in this type of pipe is a time-dependent thread, it's pure logic the crack could have only been smaller and less detectable if it was run when you allege it should have been run.

So, it's -- it would not have been discovered by an earlier tool run, and that's the ultimate irony in this allegation. We disagree with it because we don't believe it was required to be run at that time. The Company did it in any event, didn't detect an anomaly. We think the Company went beyond the minimum requirements here.

MR. SEELEY: If I may interrupt one point -- and I don't want to -- I want to try to see if I can refocus the discussion. We're tending to go into the tool run conversation. And what this allegation has to do with is the risk analysis that is to perform.

There's a risk analysis that it was to perform. There was a risk analysis that was performed which at the time assumed a tool run was going to be run. That tool run didn't occur, and then the risk analysis wasn't revised and updated to incorporate that information, which it had assumed would be done didn't get done. So, the risk analysis never got revised to reflect that the assumption that was made before actually never occurred. I don't want to get into the actual assessment being run or haven't been run. It's the risk analysis portion that wasn't updated based off of information that was assumed and eventually never occurred.

MR. HOGFOSS: But there were no changes in the input to that risk analysis.

MS. ATKINS: Yes, actually there were.

MR. SEELEY: If you assume something to occur in your risk analysis and that didn't occur, there is a change that has to be done in your analysis because the assumption put into it never occurred. So, you have to go back and say it didn't occur.

MR. HOGFOSS: But for the length of time it was allegedly delayed, there was no change that would affect a variable in a meaningful way.

MS. ATKINS: Actually Item 8 will address

the impact of the results in the TIARA model and how it's used. But in making that change to the analysis and extending that from the assumption made that it would be run in 2011, it changes the risk score and it changes the identified threats. And we cover that in Item 8. But because the answer was yes, we ran a crack tool in the TIARA questions in the input, there were no identified threats through this area.

Had the run which was done for both cases of yes or no to that answer, [sic] there were identified threats that resulted, which did require management notification in accordance with OIMS. So, by not running the tool in 2011 and extending it, you change the risk by not having identified threats. Then require management notification and mitigation, if necessary, because the risk profile changed because the tool -- it may not have even been appropriate to say yes at the time it was stated in the original run because it had not, in fact, been run at the time the risk analysis was done. There was a conscious choice to -- which we'll discuss in Item 8 -- to use yes as the answer and make the manufacturing threats go away.

MR. HOGFOSS: Molly, if the tool run was run when you allege it should have been run, do you believe it would have found the anomaly?

MS. ATKINS: That's not the question we have. That's not the allegation.

MR. HOGFOSS: Isn't that really the ultimate issue here, though, is that you're faulting the Company for failing to take certain actions at certain times that you apparently believe would have prevented this incident?

MS. ATKINS: The allegation in Item 7 is that there was a change in the conditions and the assumptions made in the risk profile and the risk model was not updated.

MR. HOGFOSS: Right. And our response to that is we don't believe it was required to have been done. So, there was a change that didn't affect the legal requirement. And ultimately there was -- had there been -- run earlier, affected the ultimate outcome. So, it's really a distinction without a difference. But we'll save it, Item 1 or Item 8.

MS. LITTLE: I think also -- and, Steve, correct me or Johnita if I'm incorrect -- but I think that when they were doing the TIARA analysis, they actually ran it both ways, right, to see --

MR. KOETTING: We ran multiple scenarios to see --

MS. LITTLE: Can you speak to that?

MR. KOETTING: -- if anything changes.

MS. LITTLE: Right.

MS. ATKINS: We'll discuss that under Item 8.

MR. KOETTING: Yeah. It's Item 8.

MS. LITTLE: Okay.

MR. SEELEY: Are we going to Item 8?

MS. LITTLE: Did you want to add something?

MS. ATKINS: We can come back around to this one after we've talked about Item 8 maybe.

MR. KOETTING: One last thing on Item 7, the process that we followed --

THE HEARING OFFICER: Sorry. Can you repeat your statement?

MR. KOETTING: The process we followed to determine whether or not to run a seam tool made the determination that it wasn't susceptible to long seam failure by the process that we adopted that was published. And, therefore, if it wasn't susceptible, I don't know how it changes an answer on the risk assessment. It would change that determination. So, the insinuation that the risk model drove the decision to run the tool was invalid. It didn't change the decision.

MS. ATKINS: Your TIARA model doesn't determine whether or not you want to run the tool. It determines a level of risk and identifies risk that then has followup actions in your procedures. So, if an identified threat there is identified -- and I think that's when we're getting into Item 8 -- there's certain things you need to do. And so, if that doesn't occur, those actions don't happen; and the risk reduction measures, whatever they are, don't occur.

So, in this particular case, it's not about whether or not you ran a tool. It's how you answered the question in the risk model and when the questions answer changed, because really it was answered wrong in the first place, it didn't get updated and actions didn't get taken, whatever those actions might be.

THE HEARING OFFICER: Anything else on Item 7 before we move on?

MR. HOGFOSS: Nothing.

THE HEARING OFFICER: Okay. Item 8.

MR. SEELEY: Okay. Well, quickly so we can get to the conversation, Item 8 is the operator failed to follow the procedures which has to do with their TIARA model, failure to --

THE HEARING OFFICER: Can you -- that

acronym?

MR. SEELEY: TIARA stands for threat identification and risk assessment.

THE HEARING OFFICER: Thank you.

MR. SEELEY: And we've already started the discussion on it. So, I'm just going to step off there and let the discussion continue.

THE HEARING OFFICER: Molly, did you have anything you wanted to add?

MS. ATKINS: The TIARA model was run with -- there's a set of questions that are asked. And one of the questions is in the risk assessment or the TIARA question process, was a crack tool run. And the answer is either yes or no, and there's a different score in the risk profile. This is the Muhlbauer risk model, and the -- it's a combination. It's the EMPCo risk model, and TIARA has a user manual for it [sic].

And it indicates that, yes or no, it's a different weighting and elevates the risk if it's no and it's a lower risk if it's yes. When they ran it by answering no, there were identified threats. An identified threat is a threat that is local to a segment. Instead of the entire weighted average of the testable segment, it's the subsegment in there. And the purpose for that is to not have the entire weighted

average outweigh the small segments that might have high risk but are then discounted because of the weighting process.

So, when these identified threats become apparent, there is a requirement to follow the OIMS guideline for management notification. It doesn't state it in the TIARA manual. It says OIMS 2A process, I believe, for your risk processes in OIMS.

MS. JONES: I'm not sure that the OIMS 2A specifically speaks to notifying management of an individual threat.

MS. ATKINS: The TIARA manual instructs you that it does.

MS. JONES: It comes out as the final scores from the risk assessment.

MS. ATKINS: So when the crack tool was run with no, there were moderate identified threats in the results. And when it was run with yes, there were no threats. The communications that were provided --

MR. WHITE: I'm sorry. Can you point out which exhibit you're reading?

MS. ATKINS: These would be our Exhibit B; and they also have Bates stamps, if you'd like, from the EMPCo [sic]. They'd also be in Exhibit A in all the materials provided, and I can read the Bates stamps.

MR. WHITE: And you're looking at this document at the top, manufacturing threat classification.

MS. ATKINS: Yes.

MR. WHITE: And it has a list of mile --

MS. ATKINS: Beginning stations and ending stations between Conway to Corsicana.

MR. WHITE: Okay. And then we have the same record for the scenario where the answer was yes in the model.

MS. ATKINS: That's correct. There are communications in an e-mail dated 3/14/2011 between David Martin and Chris Gorman, both with ExxonMobil. And this also would be in our Exhibit A and Exhibit B that said, "Go ahead and upload the risk assessment with the D3 score and no manufacturing threats so it's representative of the pipeline going forward." It says, "With the crack tool answered yes it also comes out a D3 probability...and all the threats in manufacturing went away."

So, by choosing to represent that there was going to be a tool run -- it was expected only to be a couple months after this assessment. This is March of 2011, and it was expected that the tool runs would be in the summer of 2011. There was a reasonable expectation

to represent it as if that tool run were being performed. However, when it was delayed a year and then further delayed after that, they didn't go back and look at should we do anything with these threats. They did not revise their TIARA runs, their output, because this assumption was changed in the Management of Change form. That goes back to Item 7. That's the part we were discussing, Item 7.

In Item 8, the fact that there was a choice to say no and use these results selectively allowed for there to be no action and no additional threat reduction, risk reduction taken in this area when instead of saying yes -- excuse me -- instead of saying no, they said yes in the questions; and the identified threat went away.

And as a result all the further processes -- these are, again, the Exhibit -- they're in Exhibit A and Exhibit B of our violation report -- if there are no threats identified, the process stops. And all of these subsequent actions in the emergency flow reduction, leak detection and preventative and mitigative measures will stop.

MR. WHITE: Okay. This one here, what you're referencing as a flowchart or a decision tree from ExxonMobil's own procedures. Is that right?

MS. ATKINS: These are the IMP figures 6.2, 6.3 and 6.5. If no threats are identified, then there are no subsequent actions to reduce risk. And the result of not identifying that threat was to not take any additional action.

MR. KOETTING: So, why did we run the tools then?

MS. ATKINS: Your risk assessment is not the decision for running the tool.

MR. KOETTING: Exactly. You don't understand our risk assessment process.

MS. ATKINS: Okay. Well, possibly you could explain to me --

MR. KOETTING: When we do risk assessment, it's supposed to be done, preventative and mitigative activities. We're trying to do what-ifs. What if we changed inputs? What -- would that change the risk? What you're saying, answering yes and no to manufacturing risks, demonstrates how sensitive is our risk assessment model for the inputs, which is, should we run the seam assessment tool or not.

We had already made the decision to run a seam assessment tool. The TIARA process that you're saying changes the answers from yes to no, see how it affects it, feeds right into that. It says yes.

This -- running this seam assessment tool will reduce the manufacturing threat. So, that drives our decision to run it.

It's not that we used the risk assessment to justify not running the tool. We used the risk assessment to justify running the tool, even though the seam failure susceptibility analysis is not susceptible. So, you've got it backwards. It's to help us justify running the tools by saying yes. If we -- if we run a tool, it will result in a risk reduction.

MS. ATKINS: My observation of your form 6.2, 3 and 5 in the data integration all start with no threat identified in the TIARA model and as a result, no subsequent risk reduction or evaluations were taken. And that is part of the post-assessment processes that you go through that must occur within a year after the tool is run.

So, it's not just the decision to run the tool. It's what you do with the risk information for that statement and further risk and preventative and mitigative measures, if you need additional valves, if you need to look at leak detection. And so, that feeds into all your other processes for the risk management, not just the tool selection.

In looking at these decisions, it affected

the way other decisions were made. Your TIARA manual in the beginning says, the purpose of the identified threat is not to mask a high-risk short segment over the long -- longer testable segment.

MR. KOETTING: Yeah, it does.

MS. ATKINS: Well, it does if you don't identify the threat. The highest consequences were in these areas in this segment which all had a one- or two-consequence level, which is the highest in your risk level. Yet, the overall weighted one was three. So, nowhere would that consequence be evaluated with the probability if you don't elevate the probability for a manufacturing risk to create a failure and combine that high consequence with that probability to show that elevated threat level. And that's what failed to occur in your model.

MS. JONES: We ultimately made the decision based upon the data from the model as well as the information and knowledge of the people who work the pipeline to schedule additional installations to protect the area.

MS. ATKINS: Have you installed those?

MS. JONES: They have not been installed.

MS. ATKINS: So, when did you make that decision?

MS. JONES: I don't know.

MS. ATKINS: Those are not installed? The first recommendation from the data integration team to run a TFI tool came in 2009 for 2010. They said in 2009 that you should run a TFI tool with the combo tool in your 2010 assessment. That was then delayed to 2011 and again to 2012. So, the data integration team even without this threat, I agree, said you need to run a crack tool.

MS. JONES: I think that will get back in our arguments in 1 through 4. There was also a time frame that was given with that recommendation for running that.

MR. HOGFOSS: And also, we're really drifting off what the allegation was in Item 8 at this point, which is understandable. They're all related. But if I can step back for a second, unfortunately, for a legal analysis of this.

This allegation -- and as we said at the outset, this is a complex matter. There's a lot of material. The NOPV, the Pipeline Safety Violation Report, the investigation report throws a lot of material out there. But as we're discussing these issues, it's disconcerting that when we point out an alleged fact discrepancy, suddenly the topic shifts to

something else; and it just happened in this Item 8.

So, let's step back to the beginning of Item 8. The allegation in Item 8 is made under 49 C.F.R. Section 195.402(a). 402(a) is one sentence. It says, Each operator should have an operator, an operations and maintenance, an owner manual. The manuals shall include [sic] -- address normal operations, abnormal operations, emergency operations.

The one paragraph allegation in NOPV Item 8 says that EMPCo failed to follow its O&M manual by selectively using its TIARA risk assessment process. We would actually like Ben to consider when this case is before you, Ben, a motion to dismiss this item for failure to state a claim. Frankly, it should have been brought under 195.452(b)(1). That's the provision of the rules that says have a written IMP plan that part of which is where this TIARA comes from. So, it's important.

I mean, you can throw everything against the wall, all these facts; but, in fact, you've thrown nine darts against the wall, nine alleged violations of law. We're here today to address those alleged violations, not [sic] every time you have an answer, suddenly the topic moves and we're talking about a different issue.

So, specific to the allegation in Item 8, did the Company violate its own O&M procedures? Well, we're not talking about O&M procedures. We're talking about TIARA. And then when we get to the point, then, of talking about the facts you want to talk about -- and we do have to postpone until we get back to Item 1, because we strongly believe that we were not required to get into this time loop that you're talking about.

But the Company's doing more than is minimally required, which the Agency encourages the industry -- that's the whole purpose of IMP. It says, These are your minimal requirements of, really, part 195 in its entirety. We want you to do more than what's required. We wish the Agency would at least acknowledge the fact that this company on every one of these issues has done more than required.

So, on to allegations within Item 8, when it says that you failed to consider impacts at Lake Maumelle, that's wrong. The Company did go through TIARA. They did go through OIMS. They did identify P&M measures. They are putting in EFRDs. And as you know, the rules don't require that in a certain time. So, I guess we're just -- we're troubled with not only the way that this claim is stated, but then the allegations that make -- again, defy logic because the Company did all

the things that you're saying it should have done.

And, again, ultimately would any of those as you allege have identified this anomaly? And the answer is no, which becomes very significant when we get back to Item 1. But all the things you say the Company should have done that in the Region's assessment would have avoided this incident, in fact, would not. And that should be our shared goal, is that we're all looking for ways, how can we implement the rules, how can we push technology to find these type of defects. And, you know, that's what we frankly are looking for; and that's what we know the Region is, too. And so, we're trying to get to some common ground.

We understand that the Agency as a whole has a need to respond publicly to significant incidents. But there's another way to do it, to be to push -- frankly, we'll get to it -- but what the post-incident Battelle study has encouraged as well, as well NTSB has encouraged. But now I'm getting off Item 8. So, I apologize.

MS. ATKINS: I'm sorry for digressing from the subject. I was responding to questions. But our allegation of the selective use and the communications that were underlying that would lead us to be concerned that the results resulted in the full risk assessments

and evaluation not being carried through and developing appropriate preventative/mitigative actions. It's not just the tool run itself. It's the additional things for the studies that are conducted after the assessment and data integration, those activities.

MR. WHITE: Mary, do you have any thoughts about just sort of this general issue of what integrity management's assessments, the issue of individualized threat, in other words on a stretch of HCA, which could be X length within an overall tool run?

And do you -- is it your opinion that it's consistent with ExxonMobil's procedures that this -- they're talking about an overall decision they've made to do the tool run in its entirety. But do you feel that it's consistent with ExxonMobil's procedures to sort of -- in this -- in this decision to not include this identified risk on these discrete HCA portions? Do you feel that they acted inconsistent with their procedures?

MS. MCDANIEL: Well, I think the way that these two violations are, the first one is once they said they were going to run a tool and they didn't, they didn't get the risk analysis in the time frame, it did affect that two-year time frame when you intended to do a tool run for whatever reason and then you didn't do it

until two years later. In that interim period, you should have considered the other risk factors and threats in the EFRDs and other things that are using that -- choosing the other answer, that other route. And I think that was the basis for the first one. And then the second one would be based off of the reasons you made those selections. So, I think that was inconsistent from what your procedure says.

MS. ATKINS: Your TIARA manual that you have in your Tab 7, your Exhibit 7, states in the last paragraph before Section 8.1, because of the length weighting, it is possible for an identified threat to be present and the testable segment --

MR. WHITE: Sorry. Can you describe what you're reading from?

MS. ATKINS: Sure. Reading from Exhibit 7 of the hearing brief from ExxonMobil.

MR. WHITE: Okay.

MS. ATKINS: And it is Page 120 of the TIARA model. It is the last paragraph before Section 8.1 under risk assessment driver determination.

Because of the length weighting of the model, it is possible for an identified threat to be present and the testable segment risk level to be low. To ensure that identified threats receive appropriate

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management notification and action, any testable segment with an identified threat is treated at a minimum as a low or moderate risk. Management notification and action taken is to be completed in accordance with OIMS System 2A procedures.

If the identified threat is chosen to go away, if there's a choice that it goes away in the process, then those follow-on actions do not occur.

MR. WHITE: Is that -- I think we've pretty much summed up our position. Rod, do you have any --

MR. SEELEY: I think we've got our -- I think we've covered this issue; and we'll confuse it again with the next one, I'm sure.

THE HEARING OFFICER: Let me ask: Do you have any comment to the assertion that the wrong regulation was cited for this item?

MR. SEELEY: I don't believe -- I think 402 covers all of the operation and maintenance, and integrity is part of the operation and maintenance of a pipeline. So, it's a larger umbrella; but it's still applicable.

THE HEARING OFFICER: Anything further on Item 8?

MR. HOGFOSS: We'll just note that it is a

separate requirement in the rules to have a written IMP program that addresses these issues. And in fact, in practice both the Agency and industry refer to O&M manuals and IMP manuals.

THE HEARING OFFICER: Okay. Let's -- shall we try to hammer out Item 9 before taking a break, or would you-all prefer to take a break?

MS. ATKINS: I would like to think it would be short.

THE HEARING OFFICER: Okay. Let's do Item 9 then.

MR. SEELEY: Okay. Item 9, again, failure to follow the procedures for creating a Management of Change document. This relates to when merger of segments for assessment were merged into a single segment, and the appropriate Management of Change documentation was not communicated or executed. And we've already talked about the impacts of those mergers in an earlier item, but this item has to do with not creating the Management of Change for the decision to merge the segments.

THE HEARING OFFICER: Thank you.

MS. LITTLE: The Company did do a risk analysis in 2005 that talked about what the impact of merging the testable segments would be for the integrity

management program, ILI assessment; and that analysis concluded that there wasn't any negative impact to the integrity risk assessment process. And I guess in addition, under the TIARA program, which we've just been talking about, you don't actually -- the dynamic risk assessments, those aren't aggregated. They can't be. So, they can't be masked over multiple miles.

So, it doesn't matter whether you're one, two, four, six or eight segments for purposes of how you are going to be doing the risk assessment process under TIARA. So, you cannot aggregate them. So, the length of a testable segment does not impact the risk scores. And that's, I think, from our perspective --

MS. ATKINS: Are you talking -- I'm sorry. Are you talking about the cumulative risk for the testable segment or the identified threats?

MS. LITTLE: I think that's --

MS. JONES: The individual threats for the cumulative segment itself.

MS. ATKINS: So, weighted average for the length.

MS. JONES: For the final segment. It goes back to didn't find threats but did not mask regardless of the pipeline segment.

MR. SEELEY: I don't know if they're

through.

THE HEARING OFFICER: Do you have anything?

MR. WHITE: Sorry. We interrupted -- we interrupted her.

MS. LITTLE: No. That's okay. I think that's okay.

MS. ATKINS: Is there a point in here where -- I've reviewed the MOC that's under your brief Tab 10 and brief Tab 11 and 12, and I don't see where it addresses the impacts on the ability to provide the vendor data and ILI reporting within the discovery time frames.

MS. LITTLE: And I think the way that -- I'm looking at NOPV Item 9 in the NOPV itself. And the way in which this is pled, the Agency says, "As a result of the change, the longer testable segments negatively impacted the TIARA risk assessments by masking higher threat intermediate segments (such" -- and then parens, "(such as the Lake Maumelle Watershed and Mayflower populated areas) with the dilution of the risk scores that resulted from the increased length of the testable segment."

So, again, you know, the Company did in 2005 look at that issue. And as we said, the dynamic

risk assessment threats can't be aggregated or masked over the multiple miles. So, the testable segment issue essentially goes away.

MS. ATKINS: So, as long as an identified threat is identified -- is taken care of, it doesn't matter how long it is?

MS. JONES: The identified threat should be addressed, yes.

MS. ATKINS: So, as we read in that [sic] Section 8 of the TIARA manual, it's important to get those identified threats or else the length aggregates.

MS. JONES: The risk and integrity specialist and the local risk management team and data integration team, they run their individual knowledge of that also in that review.

MS. ATKINS: But to go back to our discussion about combining those segments, was there any consideration? This goes back to the other item, impacts on the vendor's ability to meet the timing deadlines in their vendor specification for providing the reports. Since this is the MOC that was supposed to address those changes --

MR. KOETTING: They don't have any trouble running corrosion and caliper tools in the segments in that time frame.

MS. ATKINS: In the future when they would combine -- when the two testable segments are combined into one, was there an evaluation at that time about the impacts to the vendor? Because you're saying this is the MOC. And that's the question on my part going back to that other --

MR. KOETTING: You're saying that combining the segments negatively impacts the business systems. It does not. It does not impact the TIARA --

MS. ATKINS: This was an informational question.

MR. KOETTING: Whether it impacted in 2005, the running of in-line inspection tool, no, it does not impact the running of inspection tools. We are capable of running in-line inspection tools 300 miles. It can be done. Can you have problems with it? Sure. The length of the line doesn't necessarily impact the ability to get that inspected.

MS. ATKINS: Just the data analysis after the tool's removed from the line is very lengthy.

MR. KOETTING: Depends on what's in the line, what you're looking for. Depends on how many defects are in the line. You can't say that a hundred-mile line takes longer to assess than a 50-mile line. It's just not valid.

MS. ATKINS: That's the difference.

MR. KOETTING: It depends on what's in that 50-mile segment. The length of the line, as long as the tool pusher works it, doesn't affect the ability of the tool to collect data.

MR. WHITE: Let me just point out that that last paragraph -- and I appreciate the focus on what's in the NOPV. That's only fair. But the last paragraph about the impact of the change, you know, if -- even if we -- even if we take the argument that there may or may not have been a negative impact, that that sort of goes to the kind of the gravity or the consequences. And it may be a mitigating explanation that the violation or that the penalty amount on the violation should be lower, the consequence of the gravity.

But the -- I don't think that that negates the basis of the allegation, which is the operator failed to follow its own procedures for creating this management of change document.

And, Rod, can you just talk a little bit about management of change and why it's important?

MR. SEELEY: I think Molly's more familiar with their processes. So, if you keep it specific to the Exxon process instead of a generic statement, it

would probably be better.

MS. ATKINS: I was not provided this 2005 MOC. So, I hadn't had a chance to look at it until it was submitted. But I still was unclear in looking at this how this MOC anticipated the change in the combination of the testable segments at a later point.

So, if it does, I would need some help understanding that. The MOC process would be to evaluate all of the impacts of the change, and we were concerned that because of the instructions and how we understood the TIARA model, that the increased length and the weighted averages and the weight of the model worked, if we understood correctly which we may not, that there would be -- and what we observed in the calculated scores, that there was some mechanism there that was impacting the ability to identify the risk in the areas in the Maumelle and prioritization of those relative to one another for inspections.

So, that risk weighting is important for multiple decisions that are made afterwards. But the management of change itself should evaluate all the changes implications and have you taken care to address that if we make this change, it will do this and what do we need to do or do we need to do anything to mitigate that, which is in your MOC processes.

And I'm not sure where your MOC lies, the PL2311 that's under your Exhibit 11 is an MOC form number, and I don't know if this falls under your normal procedures. I know it's a requirement of OIMS; and if that filters down through your procedures -- and I don't know if it's in the IMP manual, but this resides somewhere in your procedures to complete an MOC for significant change.

MR. RANDOLPH: My understanding was the allegation originally was we didn't do an MOC, and you're saying we didn't produce it because, well, we weren't asked. So, we produced the two MOCs and we get here and now the allegation changes. It's just frustrating that we actually have the document to address it. And then now in a hearing, it's, well, I didn't get a chance to see this until today.

MS. ATKINS: I'm sorry, Johnnie, if that's what I inferred. I am looking at this. I'm just saying I had a short time to look at it, and I did not see where it addressed the intention to combine the testable segments. And they were not combined until after 2009, so --

MR. KOETTING: They were combined 2005 and 2006.

MS. ATKINS: There's also a bullet that

says station remained idle and will only use as a status surveillance site for Foreman.

MR. RANDOLPH: That is true for Foreman station, yeah, at that time.

MS. ATKINS: At that time. Is it in use today?

MR. RANDOLPH: If so, we would have included it in a change before we activated it.

MS. ATKINS: This removal of scraper traps does not discuss combining testable segments. Testable segments are an IMP plan, not a physical structure. So, I guess I could not read into here or obtain from this information where the implications of combining the testable segments, which have a lot of things to do in your risk model and your assessments, where this was addressed.

MS. MCDANIEL: Or that might have been a change that addresses the change from four testable segments to two testable segments.

MS. ATKINS: That's the part that I don't find in here. And so, all I'm saying, if it's in here, I don't see it; but I've only had a short time to review. If you can provide me an explanation of what shows the evaluation of the combination of the testable segments --

MR. WHITE: Yeah. Maybe there's some additional records that can be provided in this hearing on that issue, and that would clear it up.

MS. MCDANIEL: I think that addresses your question, that the allegation is that there was not an MOC for the merging of the testable segments. And that's what I think we're saying, is what we see here doesn't seem to respond to that for that -- I mean, yes, it was a management change form; but it's not our allegation from four testable to two testable segments, that that was created for that purpose.

THE HEARING OFFICER: Okay. Anything further on Item 9? Okay. I suggest we take a 10-, 15-minute break and resume with four Items 1 through 4. We're off the record.

(Recess from 10:01 a.m. to 10:17 a.m.)

THE HEARING OFFICER: We'll go back on the record. And we just finished with Items 5 through 9. Did anyone have anything to add before we move to Item 1?

MS. LITTLE: Yes. We wanted to just revisit one thing for clarification purposes with respect to TIARA, and this relates to NOPV Items from back towards our discussion for 8 and 7.

THE HEARING OFFICER: Okay.

MS. LITTLE: Just to clarify for everybody's benefit, the purpose of TIARA -- which is meant to be a five-year forward look. So, when you say, yes, we're going to do an ILI assessment, it means that the ILI's going to be done somewhere in the next five-year period. That's how it's designed. So, we wanted to make sure that was clear in terms of what the purpose of TIARA is. So, when you're putting in the inputs, it's considering them for the next five-year period, irrespective of when it is you're doing it within that five-year period.

And then the other point of clarification we wish to make is that when you're running a sensitivity analysis, you're not manipulating the process. You're simply -- it's almost like a cross-check of the process. And we wanted to make sure that that was clear as well.

THE HEARING OFFICER: Okay. Thank you. So, Items 1 through 4, we're going to do those individually, right, and in order?

MR. WHITE: Yeah. Rod, do you want to start with that?

THE HEARING OFFICER: Okay. Item 1, please.

MR. SEELEY: Okay. Item 1 of the notice

alleges that the operator didn't include all relevant or pertinent information in determining the -- in performing their assessment schedule which relates to -- specifically, the operator did not include information regarding material and other test data that they had to create their assessment schedule or get the assessments for the Pegasus Pipeline, things that were not concluded from our analysis [sic] or review, manufacturing information, toughness, again hydrostatic testing history, all related to the low frequency ERW pipe in their system.

THE HEARING OFFICER: Thank you. Okay.

MR. HOGFOSS: You want us to go ahead?

THE HEARING OFFICER: Yes.

MR. HOGFOSS: I guess kind of a threshold, Items 1 through 4 are clearly related; and it's primarily the issue on Item 1. So, I expect we will have the most discussion there. And then 2, 3, 4 are really kind of a footnote to Item 1 in series.

But to begin with and just to kind of preface our discussion on those four items, you know, the way we read the NOPV and the related materials, the violation report, is that clearly it presumes that simply because the incident occurred, there must be a violation of Part 195 regs; and that's not the way that

the Pipeline Safety Act or the regs are written.

The regulations establish minimal standards that industry must meet, and the intent is and the hope by both Agency and industry is that that will detect and prevent incidents. And, in fact, something we've said in our written materials, we think the Agency should take credit for the fact that certainly the IMP rules over the last 12 years have had a positive effect.

If you look at the data, a couple of notable achievements, that certainly the -- 12 years ago the leading cause of pipeline incidence was third-party strikes. That's -- the incidence of third-party strikes has plummeted largely as a result of the "call before you dig" regulations and the efforts made by both industry and agency with 811.

Then the leading cause of incidents became corrosion and really helped force [sic] that technology, the development of corrosion and in-line inspection tools that would better detect corrosion. And the IMP rules as we were discussing earlier established timelines, criteria for repair; and that's had an effect. There's been a decrease both in number and size of those types of incidents.

The leading cause of pipeline incidents on liquid pipelines now is material defects, which is where

we are with this issue. The issue for Items 1 through 4 has to do with pre-70 low frequency electric resistance weld or ERW pipe. And the difficulty -- I'm sure we'll be talking about this a fair bit. But the difficulty that the Agency recognizes, industry recognizes, the scientific community recognizes is in finding all of those defects.

But the starting point for us is that simply because an incident occurs does not necessarily mean that there's a violation of the regulations. It may in many cases or in most cases, and that's something that we'd be curious to hear the Agency's response on. But the law simply isn't written that way. It could have been -- strict liability is the concept where there is liability without fault.

And the Clean Water Act has that specific to oil pipelines. It says if you spill oil in U.S. waters, you are liable for a penalty regardless of how it happened. We don't care what the cause was. Congress didn't say that for the Pipeline Safety Act. So, that's an important starting point.

Again, we all wish this incident wouldn't have happened; and we'll come back to that, too, is that we scratch our heads as to how anything alleged as violations in here alleged that the Company failed to do

something that would, in fact, have found this anomaly in time to prevent it. And that's an important concern, and we will eventually come back and certainly want Cliff's input from his years of NTSB as to what can be done, what's the state of the art right now; and that's important.

There's a lot of things as the Region certainly knows and refers to in some of the materials that have been done even since this incident occurred. And we'll want to talk about that.

MR. SEELEY: Before you go on, can I ask one question?

MR. HOGFOSS: Yes.

MR. SEELEY: You made a statement that you presume that this item is in here solely because of an accident that occurred. Can you point in the notice where you draw that conclusion?

MR. HOGFOSS: I think the entire -- I think all of the -- the fact of the enforcement itself, we wouldn't be here at this table today if there wasn't an incident.

MR. SEELEY: Is there particular verbage verbiage in the notice that says that?

MR. KOETTING: Probably the first sentence. March 29th it says pipeline ruptured.

MR. SEELEY: That's just the fact of an event.

MR. KOETTING: Yeah.

MR. SEELEY: It's not the basis of the notice.

MR. WHITE: It gave rise to the investigation.

MR. HOGFOSS: Yeah. Actually in the Pipeline Safety Violation Report, too, it says that the Company failed to do all of these things, you know. And, yet, it doesn't say they would have prevented an accident. But clearly -- I mean, the point is if there wasn't an incident, we wouldn't be here.

Perhaps a more direct response would be, that the Agency had inspected this Company, this specific pipeline, did have a very thorough audit in 2007 of these exact processes, IMP and TIARA and OIMS, long before this incident occurred and found no fault with the processes then. So, there was no glaring mistake in the process.

MR. WHITE: I think one thing that Rod's trying to get across, though, is you're right. It's not a strict liability; but I think it's incorrect to say that just because there was an accident, there's always an NOPV. I mean, there are times when accidents happen;

and the investigation determines that it was because of -- there was a third-party strike the month before or something and there was no probable violation. It's not the case that just because a spill happens, we automatically generate an enforcement. That is not the case, just to be clear about that.

MR. HOGFOSS: Well, again, though, I will say that the Region has inspected the Company's programs and processes and specifically this pipeline and did find no glaring error. And now after the incident, you know, there's a lot of alleged violations that we think are not proper.

But it does get to the point of really what do regulations require, and the regulations clearly, especially integrity management, but all of Part 195 are process-oriented. They say establish -- each operator establishes a process and a set of written procedures. And your written procedures have the force of law. We'll inspect them. We'll review them again after there is any type of incident. And if you're not following the rules and your procedures, that's a violation. We understand that. But we disagree in this case.

And I guess we should move into Item 1. I've been trying to postpone it, Rod.

MR. SEELEY: That's all right.

MR. HOGFOSS: But here's the -- again, the legal issues presented as specific nine alleged violations, it really goes to processes. But as we included in our written materials -- and this is clear in the IMP regs -- the Agency requires and industry responds that it's a continual process. It never ends. It's a loop where you are constantly doing inspections.

And the point here is at a very broad level on Item 1 is that this isn't a case where you have an operator that just really failed to be looking at its assets. In this particular pipeline where this incident occurred, the Company had done three hydro tests. It had done three in-line inspections, one of which was with a seam/crack tool. And it did four susceptibility failure analyses or engineering analyses. So, it was clearly looking at this issue.

And in the process of that, which really went on over a couple of decades, think of the dozens and dozens of engineers and managers reviewing all of these issues, reviewing the rules and the procedures, the engineers within the Company, the engineers at the tool vendors looking and grading the results. The metallurgists looking when there are hydro test breaks and giving their third-party reports, certainly

post-incident, the -- all of the various experts looking at things.

And most importantly, when it comes to experts, someone that the Region notes in the supporting materials to the NOPV, being primarily the Pipeline Safety Violation report, there's an accurate history that chronicles how government, industry and the academic community has looked at this ERW pipe issue since the 1980s.

And from the very beginning who the industry has trusted and relied on this to as recently as January 2014 is the metallurgist John Kiefner who is getting older now but is really the leading authority who has been cited by the Agency, who has been hired by the Agency, just published a report in January of this year on this very issue.

And significantly, the Agency retained John Kiefner and Michael Baker in 2004 to prepare an analysis on this very issue, to ask them, to say please help us analyze what are the best tools to look for ERW defects, what are the best processes that we can consider to require or recommend as guidance for industry to look for ERW defects. And the Baker/Kiefner report came out, and it provided a proposed methodology to do just that.

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The Agency recommended it as guidance, did not change any rules. Actual rules in Part 195 that address the ERW are quite minimal. They say if you -- if you find that there's a threat to when you go through your IMP process to identify threats, then you need to do -- you need to look at P&M, preventative and mitigative measures or you need to do an engineering analysis to look at it.

So, what this company did -- and it's in the record -- they actually hired John Kiefner -- we're not talking post-incident. We're talking about when the IMP rules first came into effect -- to actually help the Company work through the report that the Agency commissioned, the Baker/Kiefner report, and apply it to their processes. And John Kiefner helped this company come up with a software program to implement which the Company uses today, which many companies use today.

You fast forward that a ways and Kiefner and another national expert named Kent Muhlbauer, who's really one of the leading authorities on pipeline risk management, also worked with the Company early on in their integrity management planning process and had input. Both of those experts now after the fact, the Company asked them to look again and say help us understand how this happened, how we can avoid this in

the future, how we can improve our methods, our tool selection.

And you'll see as Exhibit 1 in our materials, the affidavit from John Kiefner that says very clearly -- and let me actually turn to -- I believe it's in Exhibit 1, Paragraph 23 and 24. 23 John Kiefner is saying that he's discussed these ERW detection issues with the OPS, with the Agency recently. And the Agency's aware that there's not one tool that can be expected to identify all ERW anomalies all of the time.

What he's referring to there is, in fact, the most recent report. We'll come back to it and how that report came about, what we're referring to as the Battelle report. But that concluded as well is [sic] that, you know what, we're not there. We're not there with technology yet. We're not there with management procedures yet. And in fact, the Battelle report concluded by saying it is urgent that both PHMSA and industry work to force technology, work on this further.

We find that in stark contrast to the NOPV which accuses this company -- and it says it quite clearly in the violation report -- that the Company had more than adequate information to be able to find this defect. That flies in the face of everything the Agency's done, including post-incident Battelle report.

Most importantly, it flies in the face of what John Kiefner himself says here.

If you look to Paragraph 24 in his affidavit, he says he has reviewed the data. He reviewed the metallurgy reports for the root cause failure analysis submittal. And he ends at Paragraph 24 saying that based on his considerable experience, it's his opinion that "the pipe at the point of failure was unique, that [sic] the anomaly that caused the incident was not capable of reliable detection given that it exhibited atypical characteristics not frequently seen before in the industry."

You really can't find a more relevant expert to opine on this. He's been working on this issue for decades for the Agency, for the industry. And to us, that really is the entry point to us discussing Item 1. If the Company's criticized for failing -- failing to consider all of the required information in order to identify the risk of seam failure on ERW pipe, our response is we did. We did consider it.

We're being faulted because we didn't conclude that there was a risk and, yet, the Company proceeded as if there was. They didn't simply say, no, we think this one's fine. Forget about it. They've done hydro tests. They've done ILI. They've done

engineering analyses.

So, that's the entry point. I don't know if anyone else on this side wants to add something. We should let Rod and company respond at this point. I'm sure we have more to talk about.

MS. LITTLE: I don't know if you want to go to the specific points yet or just wait.

MR. HOGFOSS: It's up to you. Shall we open the floor on this one? Or do you have anything more to say as kind of an opening?

MS. LITTLE: Well, I think just to harken it to -- and I think that is the background that's appropriate for discussing Item 1. The allegation itself is that the Company didn't -- did not -- we think that the allegation essentially is saying that the Company didn't conclude that the pipeline was susceptible to seam failure, and that is the issue that the Agency has with the Company.

And as Bob said, the IMP does not require an operator to conclude a risk exists. It requires you to consider that there are all these different risks. And you may conclude based on what your various end points of -- input of information, your data points are, that it exists. But it doesn't require a conclusion. It doesn't force a conclusion. It forces consideration.

And Part 195.452 says you have to consider all nine applicable threats, including manufacturing history, including prior integrity assessment result and you need to document that process. And we think we've established both in the brief and the exhibits that the Company did just that. They evaluated all the risk factors, including seam susceptibility, multiple times based on all the available information.

And when the Company first prepared its IMP program, the BAP, the Company incorporated a long seam failure susceptibility process based on the Baker report and with input from John Kiefner himself at that time. And I think both Kiefner and Muhlbauer in both of their exhibits -- I mean both of their affidavits -- talk about that process, the preparation of the program and the status of the Company's program today as being robust.

Kiefner, as Bob mentioned, created the Pipelife [sic] for -- at the request of the Company and then later made that available to the industry to help analyze the pressure cycling and used fatigue data as part of the long seam susceptibility failure analysis. And the Company both -- and I think Bob detailed the years. We have an exhibit, I believe, that goes through all the different years in which the seam susceptibility

failure analysis was conducted, 2004 and 2005, again in 2007, again in 2009, and again in 2011.

And every time using the process that was developed with Kiefner himself, the Company concluded it wasn't susceptible to longitudinal seam failure. And in making those determinations, the Company looked at all the pieces of information that the Agency expects the Company would look at: Pipe manufacturing information; leak history; prior pressure testing; third-party metallurgical analysis of the 2005, 2006 seam failure; using the PHMSA-endorsed Baker and Kiefner process; consultation with Kiefner himself; and let's not dismiss over 60 years of operating history and maintenance history.

Kiefner himself says, I think it's in Paragraph 13 of his affidavit, that -- 19? 13. "Hydrostatic test failure alone is not an indication that a pipe is susceptible to seam failure." There has to be evidence of fatigue-related failures, selective seam corrosion or other time-dependent defects.

So, what Kiefner then says is, If -- and I think this is also in the Baker report, 2004 -- if ERW pipe -- no threat exists if ERW pipe is successfully hydro tested, operated in a manner that stress [sic] levels and pressure cycling prevent [sic] it from being

susceptible to fatigue and adequate coating and CP exists to prevent selective seam corrosion.

So, the Company applied its long seam failure susceptiblity analysis to Pegasus, factored in all those results into its threat identification and risk assessment analysis and concluded time and time again that this particular line was not susceptible to seam failure.

Do you want to add more?

MR. HOGFOSS: What the ultimate irony is that the Company did use a seam/crack tool, we believe not required to do so but they did on this line, and it did not find this anomaly. That's what John Kiefner is speaking to saying -- and they used multiple tools at this point. And John Kiefner said, you know, there is not a tool out there.

Now the Pipeline Safety Violation Report goes so far, which is beyond the statement of the law, to say that the Company should have used a different tool, should have known that a TFI tool would not find this. And says you should have used the UT tool or an EMAT tool. Well, the law doesn't say that; and the experts -- the dozens of engineers and the very experts retained and commission by the Agency clearly say there is no one tool that can find ERW all of the time.

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They recommend doing hydro tests. The Company did that on this line. They recommend doing multiple tools. The Company did that on this line. So, that is the ultimate irony here. We are here, all of us, only because this incident occurred. And the ultimate irony is had the Company done everything that it's alleged to not have done, it still would not have found this particular defect.

That doesn't mean the ERW defects are not found often. They are. And the technology is improving, and the methodology and the industry and the Agency's ability to sift through all of the data and find these highly unusual defects is improving. But there's nothing that would have found it in this case short of perhaps a hydro test done in the last couple of days. It appears that this was a very rapid growth fracture that happened in a matter of days.

So, a tool run, multiple tool runs a month before, a year before, well, didn't find it. And, you know, again, that's the backdrop in which we're talking about this. And I know that we do all share the goal of how can we get -- it would be nice if we would look to the allegations in the NOPV and say, yes, but for that alleged violation, we would have caught this one. But that's not the case, and that's very important for the

entire backdrop to this matter.

MS. LITTLE: And I think the last point we can make, too, is just looking, again, at Kiefner. And we mentioned before PHMSA has obviously inspected the Company numerous times but in particular did an in-depth inspection in 2004 -- I mean, 2007, excuse me, of the Pegasus Pipeline of the long seam failure susceptibility analyses that have been done of the Company's process for how it is they conduct that engineering analysis, and there weren't any issues raised. And not surprisingly, Kiefner didn't raise any issues either.

In his affidavit in Paragraph 19, he's very clear, "I have reviewed the integrity data that would have been available to EMPCo prior to the incident regarding the Conway to Corsicana testable segment. Based upon that review, EMPCo's conclusion that the segment was not seam failure susceptible under federal regulations was reasonable and was consistent with the seam failure susceptibility determination guidance available prior to March 29th, 2013."

Nevertheless, the Company conducted -- EMPCo conducted the hydrostatic test on the Conway to Corsicana segment in 2006 and a seam integrity assessment in 2012 utilizing an ILI crack detection tool. Neither of these activities, unfortunately,

revealed the presence of the defect that was the origin of the March 29, 2013 failure.

Even Kiefner has reviewed and knows what the Company has done here to determine whether or not this line is seam susceptibility, is susceptible to seam failure. And Kiefner is the leading expert. I think that's at this point fairly well-accepted on these very issues with respect to this very type of pipe. And obviously we find that compelling, and the Company believes that it's done this process just as it should have done this process.

MR. HOGFOSS: Open it up for discussion?

THE HEARING OFFICER: Thank you. Anything in response?

MR. SEELEY: We can start a little bit of discussion. I want to go back to that the -- we sort of get to the conclusion, but the allegation is actually to the methods and processes that get us to the conclusion, not the actual conclusion itself. But we end up at the conclusion because that's what happens when you run through a process.

You referred to many times Kiefner's affidavit. And since he's not here, I guess I'm going to ask you-all about it, since he's not here for me to ask him. One thing, you also referred to the Baker

study in which Kiefner & Associates was a coauthor, if you will, or a participant in that study.

The one question I have is a seemingly inconsistent statement between his affidavit and the study itself or Item 13 you brought up that says hydrostatic test failure alone is not an indication that a pipeline is susceptible to seam failure. That's Item 13 from his affidavit.

THE HEARING OFFICER: You mean Paragraph 13?

MR. SEELEY: Yeah, Paragraph 13, of his affidavit. And then if you turn to the Baker study, Section 4.3.2 starts off with, "If seam-related in service or hydrostatic test failure has occurred on the segment, the segment is considered susceptible." So, I'm wondering, could you help me understand the seemingly conflicted statement between the two?

MR. HOGFOSS: Well, first to comment that Kiefner's not here. He's semi-retired.

MR. SEELEY: I can't ask him. So, I have to ask you.

MR. HOGFOSS: He doesn't need to be here. His statements are quite clear and unequivocal and they're not isolated. We'll get to your comment about Baker in a second. But they're consistent. They've

been consistent as cited in the violation report for the last 15, 20 years on this issue.

MS. LITTLE: And actually I think they are consistent. The point that is made in the Baker report is if a seam related either in service or hydrostatic test failure has occurred, what Kiefner is saying is hydrostatic test failure alone isn't an indication and he talks about the different reasons. And he talks about the different reasons and you want to investigate them for fatigue or selective seam weld corrosion or other time-dependent phenomena.

And what he's saying is if it's neither fatigue-related crack or more selective seam weld corrosion, nor evidence of another form, it's reasonable to certify that they're not an indication that the pipeline is susceptible.

MR. SEELEY: So, he seems to jump to the -- to the point that his analysis is related to or his conclusion is seemingly related to pipe of a ductile nature that will fatigue over time and not specifically dealing with pipe of a brittle nature that would not experience that same fatigue growth. But, in fact, we have evidence that your pipe and other sections of this pipeline exhibit more of a brittle nature than a ductile nature. So, the applicability of his statement or

analysis would be flawed in that ductile pipe does not act like brittle pipe. Would you agree or disagree with that?

MR. KOETTING: It does not. You are correct. A brittle piece of pipe with a defect in it will fail at lower hydrostatic test pressure than a more ductile piece of pipe. You are correct.

MR. RANDOLPH: Can I just --

MR. KOETTING: What is counterintuitive, though, is when you look at brittle pipe failure and aggressiveness versus ductile pipe failure, almost every time ductile pipe has a shorter reassessment interval than brittle pipe, almost every time. The defect that survives is so much larger.

MR. SEELEY: But you're also jumping to the conclusion and not the process of identifying this pipeline as susceptible. So, you've jumped to the, I have longer time to assess it situation instead of do I even need to address that risk factor. You just jumped over it again. I'm trying to stay into the process of identifying as we need to be considering this line susceptible.

MR. RANDOLPH: I just want to clarify the original question about the Baker report and whether it was inconsistent. You have to read further down in the

Baker report at Page 26 where he says, "Failures that occur during the hydrostatic test should be investigated for evidence of fatigue." He then later continues, "If no fatigue-related failures exist, it is reasonable to certify that the pipeline is not susceptible to seam failures in the context of the Federal Integrity Management requirements." That's a direct quote from the Baker report.

MR. HOGFOSS: But I don't think he considers that --

MS. ATKINS: Further in the Baker report, he also premises that on if this test is sufficiently high enough. And so, sufficiently high enough is --

MR. SEELEY: It gets back to the previous testing parameters and whatnot. Also, it solely relies on the fatigue and the ductility. In the report it talks about things to consider, which goes back to the allegation of items that need to be considered is the -- for example, the toughness of the pipe. And specifically applying the toughness values of this pipeline would not lead you to the ductile pipe, which would be related to -- it creates a brittle pipe situation which creates a different scenario that you have to evaluate.

MS. ATKINS: But it's brittle in the area

of the ERW seam. We aren't saying the body of the pipe, but the seam itself is exhibiting those brittle -- [sic]

MR. SEELEY: So, you can't keep continuing to do the ductile fatigue analysis because you know at some point it's not that type of characteristic. We didn't see that being considered in your analysis as well.

So, I guess I'd like to ask, you know: How did you-all incorporate that particular piece of information into your analysis process that it wasn't ductile? It was brittle? It won't experience the same fatigue phenomenon as you maybe experienced in other areas. We have to consider that and address that.

MR. HOGFOSS: Engineers clarify this, but your point is well taken but for the fact that it's not as though the Company said, oh, this is not seam susceptible; so, we won't consider it further. They did. They did hydro test. They did ILI. They did engineering assessments, and they included and considered all of these factors. Those are the factors that are considered.

MR. SEELEY: The question of the hydro test is not simply saying, I did a hydro test. There are types and methodologies within a hydro test that go to address a particular risk. In our evaluation of the

records, the hydro tests that we see do not seem to be demonstrating that the operator was addressing that particular threat. They did a strength test, not -- a normal hydrostatic test does not necessarily evaluate particular seam flaws that this would require.

And in the literature you will find that they would recommend the hydrostatic test at a higher pressure level, stress level within the system. Those were not conducted.

MR. HOGFOSS: A couple of questions. So, what does the IMP rules say, and further O&M rules, in terms of hydrostatic test pressure for ERW pipe? What do the rules say?

MR. WHITE: I can answer that. Actually if you look at the pressure testing code, which is in Part 195 and you go to 195.303(d), it actually does address ERW pipe. And I'll quote it. And this is not from an opinion by anyone's expert. This is the black letter of the code. 195.303(d), and I'll quote, "All pre-1970 ERW pipe and lapwelded pipe is deemed susceptible to longitudinal seam failures unless an engineering analysis shows otherwise."

So, I think to Rod's point --

MR. HOGFOSS: But was asking about hydrostatic test pressure. But we'll come back to that.

I'm glad you brought that up.

MS. ATKINS: As an assessment method, if that's what you're asking, Subpart E hydro test is an assessment method.

MR. WHITE: I want to make the point that the presumption -- we've talked about ERW pipe. And just to step back for a minute, I mean, the reason why that's in the code and has -- and the reason -- ERW pipe, there is extensive metallurgy that has been done with failures related to that. And the fact that -- and I think everyone's acknowledging that there were hydrostatic test failures.

And the integrity management regulations require an operator to consider all available and relevant information. And so, if we had a situation where ER -- where we know we have ERW pipe, the code sets up a presumption that the pipe is susceptible -- and this doesn't even say there had to have been failures. And then you add on top of that there were hydro test failures and then you look at the nature of the hydro testing that was done, you know -- so, you know, Bob, you talked a lot about the issue that this particular flaw failed at the Mayflower site possibly couldn't have been found even if a different type of tool had been used because of the state of the

technology.

But, again, the allegation is not that the operator did not find that particular anomaly. The allegation is that in its procedure, in its overall process of implementing the risk model, that this risk factor should have been accounted for in a way that it wasn't. So, I just wanted to clarify that.

MR. SEELEY: To answer your question, literature and the documentation in the analysis would show that a hydrostatic test within the pressure ranges from 90 to 100 percent SMYS would be the test that is considered one that would assess for the seam risks or threats. The test records that we reviewed showed that the line was not subjected to that particular type of test.

MR. HOGFOSS: And the point I was getting at was that the Agency has not promulgated a rule, and we're talking about violations -- alleged violations of rules, of the law. The Agency has not promulgated a rule that tells you what test pressure to test ERW pipe. Also, 303(d), I don't have it open in front of me, but I believe it says risk-based alternative, right? It was promulgated in 1998. It was a one-time opportunity for operators that wanted to elect a risk-based alternative --

MS. LITTLE: As opposed to testing.

MR. HOGFOSS: -- to testing. The Company did not elect that. That's totally irrelevant. I understand what it says. We understand what it means. It's not even alleged as a violation in the NOPV. And really the only benefit it has for the Region's position is it says in that case if you raise your hand, you will deem for purposes of being allowed to use a risk-based alternative -- this is pre-IMP, remember. It was kind of the evolution of IMP -- you will be allowed to do that if you deem it seam susceptible.

But then we fast forward to -- and I understand. Rod's absolutely right. What the current state of the science seems to be is that when we look for these -- and, yes, brittle pipe is a concern. How do we find it? How do we find these hard-to-find defects, one of the things that came up, again, post-incident?

So, right now the state of the agencies -- and the Agency hasn't even endorsed it. It simply paid, commissioned, Battelle and DNV, Det Norske Veritas, and John Kiefner to look at these issues. They came out with a still work-in-progress report October 27th last year. John Kiefner's Report Number 3 within that, very specific to this issue, came out in January of this

year.

And they do say in there, they say -- well, they say a couple of things. They say this is a tough issue. We don't have the answer. NTSB told us to identify actions that operators could implement. We don't have a silver bullet here. What we do know is that we're getting better. The technology can be forced the same way it was for corrosion. And it says -- it ends with saying, two quotes from the end of the Battelle report from October 27th. There should be an urgent effort by PHMSA and the industry to develop an enhanced technology that will identify ERW defects.

The next paragraph they say, It is clear that gaps remain, both in understanding the ERW failure process and in quantifying the effectiveness of current methods to manage ERW. That's state of the art. That's post-incident. And in that report, they do say -- as Rod was stating, that say, you know, run higher test pressures. Well, that's what this company is now doing. That's the ultimate irony, is that, yes, the Company concluded using the Agency's recommended guidance because it was not in the rules to follow the Baker report. The Company did that.

Consultation with John Kiefner concluded -- John Kiefner says now after the incident

that it was proper to conclude that it was not seam susceptible; and, yet, they still did more than what was required by the IMP rules. They continued to assess. They ran a crack tool. And that's the irony, I find, is that the violation report critiques them and says, Well, you ran the wrong tool. Where in the regs or in the guidance does it say what tool to run? It says use a tool capable of detecting cracks.

So, I mean, these are part of the problems we have with the allegation the way it's made. And hindsight is perfect, but you have to go back to what are the elements of their claim. What's a real violation here? And shouldn't we -- and this was our impression in our pre-hearing brief as well. Shouldn't we be doing what the recently 4.2-million-dollar Battelle-commissioned report recommends, is that both the Agency and the industry keep working on this, instead of doing Monday morning quarter-backing and slamming a company for failing to do things that they actually did?

And with that, I'll let the engineers talk more. Sorry.

MS. ATKINS: I have to accept that there are some things that that Battelle report says, particularly that the Pipelife model and similar

log-secant models are not appropriate for the materials. And if you go back to the Baker 2004 report, the purpose of that report on Page 6 of the Baker report was to evaluate the acceptability of using ILI technology to evaluate the integrity of low frequency ERW pipe seams in lieu of a hydrostatic test as currently required.

The conclusion of the report was very specific as to whether or not it was brittle or low toughness materials well below 25, which all of your materials are in the three to four range from the hydrostatic test and the failure site and would have concluded that this needed to be hydrostatically tested due to the low toughness and would have had superior results to the ILI.

We've not alleged that as a violation. What we have alleged is that the results of the previous integrity assessment, defect type and size that the assessment method can defect and the defect growth rate, you've demonstrated and repeatedly stated that there has been no fatigue observed in any of the 11 seam failures or this one. Yet, you continued to use fatigue crack growth model or the assessment without looking at toughness, without looking at the rest of the Baker report.

And so, it appears that there were

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portions of the Baker report that were incorporated into the processes but not the rest. For example, I think Kiefner's statement is interesting, and not just the things that he says but the things he doesn't say. He says that EMPCo followed the flowchart, but he didn't identify which one. Because the Baker report has two flowcharts. And Section 4 that you included in your exhibits, there's Figure 1. That report clearly states that that has evolved over time and it has updated to Section 9. There's a process in Section 9 that was available in 2004 at the time of the report that has a slightly different process and requires an engineering analysis.

This is not part of your IMP procedures that I could find. So, the Section 9 of the Baker report that took Kiefner's work, which he was an author to, updated it and said that these are additional learnings and additional practices that we recommend. So, when I look at your continuous process, learning and use of all available information, it appears that there are pieces that are used but not all of it.

And in his statement that you are using, the flowchart, by not saying which one, it's clear to me that there are statements in here that are maybe missing. What's the relevance of the hardness that he

mentions? Hardness is not a factor in the Pipelife model or the fatigue crack growth. He doesn't mention toughness. Toughness is a very critical factor in all of the modeling and the use of pipeline and the commonality among the 2005, 2006 hydro test failures and the metallurgical reports. And those determinations and similarities clearly point out a brittle ERW seam that does not appear to be considered in any of these processes.

The size of the defects that were observed in the failures appear to be below the threshold of detection for a TFI tool -- a TFI tool has to have a .1 millimeter air gap for the crack opening. A UT or EMAT has zero millimeter stated, as you provided information to us that the tools you want to use in the future. While that still is not a guarantee, we agree that -- with you that there are things we need to learn.

But not learning from the information that we do have and applying it in the processes and the selections of the risk assessments is the allegation here, that you had information from these previous assessments about the material properties and the processes that were recommended in 2004 that were not applied.

MR. RANDOLPH: So, you disagree with the

Baker report because it says crack growth rates are not affected by toughness?

MS. ATKINS: I was looking at the very first page of the report that identifies the four factors for crack growth rates.

MR. RANDOLPH: So, you disagree with Kiefner saying crack growth rates are not affected by toughness?

MS. ATKINS: That's not what I said. It's the remaining size that's there that has to grow. What can survive the hydro test has to do with the toughness, and toughness is one of the inputs in the Pipelife model. So, you have to know --

MR. RANDOLPH: So, it was considered.

MS. ATKINS: If it was considered, how was it used?

MR. RANDOLPH: In the model.

MS. ATKINS: But the model is for fatigue crack growth, which you've demonstrated repeatedly that you have not had any fatigue crack growth. You've had no fatigue failures.

MR. RANDOLPH: Right.

MS. ATKINS: So, why would you continue to use a reassessment interval and long seam failure susceptibility determination process that relies on an

experience that you aren't having?

MS. LITTLE: To continually evaluate, to ensure that something hasn't changed.

MS. ATKINS: But there are other failure mechanisms occurring. Because if you have a failure at a lower pressure than what was previously experienced, it could be a pressure reversal. It could be some environmental cracking. It could be hardness issues related to the seam that is a manufacturing defect, and the process as observed don't take those into the decision process as risk factors for this pipe.

MR. HOGFOSS: The record does show that the Company considered all of those factors in its engineering analyses. John Kiefner certainly concluded them in his review of the metallurgy report that went in with the --

MS. ATKINS: I don't see where he saw the metallurgy report for the hydro test, though. Did he get those?

MR. KOETTING: He's had those for a number of years, and he has them for this.

MS. ATKINS: Did he review them for the purpose of this testimony?

MR. KOETTING: He has reviewed them multiple times.

MR. HOGFOSS: But not only --

MS. ATKINS: For the purpose of this affidavit, did he review them?

MR. HOGFOSS: Yes. He has all of that information.

MR. KOETTING: He has all of our data.

MS. ATKINS: Because he was very specific about what data he reviewed in his statement, and he didn't mention those.

MR. HOGFOSS: Here's a problem that occurs to me. So, you have decades -- and I said this before -- of dozens of engineers, including engineers and experts recognized and hired by the Agency itself that have all looked at this data, reached the same conclusion. And essentially you're telling us that you disagree with all of them.

MS. ATKINS: I agree with many of the statements in here. They're carefully qualified, such as not being able to detect this. Well, whether or not you would be able to detect it is not our allegation. And his previous studies said that the appropriate assessment method would have been a hydrostatic test.

MR. HOGFOSS: Do you believe that if there were no violations, if the Company did everything you say they should have done -- which, in fact, we're

showing in documents is that they did, in fact, do it. It may not have been at the exact month that you're saying, but they did more than required voluntarily. Are you saying that if they had done it exactly the way you predict, they would have found this defect?

MS. ATKINS: I am not making any allegations or suppositions --

MR. HOGFOSS: That's not important to the Agency, then.

MS. ATKINS: It's very important to us, which is why we go back and look at the processes and discuss what are apparent causal factors in any aspect of a failure investigation.

MR. HOGFOSS: What is the purpose of this enforcement action, then, if it's not to point out these violations? Is it --

MS. ATKINS: Typically it's corrective action.

MR. HOGFOSS: Right. So, again -- and I'm honestly having a hard to time kind of matching this up. The alleged violations, asking the Company to take certain actions, in fact the Company did -- they did consider P&M measures and putting in the EFRD's. They did run a seam tool, even though they concluded --

MS. ATKINS: We need to get back to Item

1.

MR. HOGFOSS: Excuse me.

MS. ATKINS: I'm sorry. We need to get back to Item 1.

MR. HOGFOSS: This is Item 1. This all relates --

MS. ATKINS: Item 1 doesn't have P&M measures in it.

MR. HOGFOSS: This all relates to the fact an incident occurred because -- a defect was not detected. And we -- I find it troubling that the Agency takes the position -- it certainly implies in here for the public that had the Company simply complied with the law, this would not have happened. It's nice that you carefully stated it so you're not saying that; but that's why we're here contesting all of these nine alleged violations, which is unusual after an incident like this. But it's also unusual that a company was actually complying with the regs, its own procedures, and doing more than required. And the goal here should be how do we find the next one for all of us.

MR. SEELEY: I guess it seems to me we've reached a point where we are disagreeing.

MR. HOGFOSS: I think we reached that in our response.

MR. SEELEY: I think we're circling the conversation around a disagreement that I don't know is going to be resolved by continuing to say we disagree.

MR. WHITE: But it might be helpful, Rod, to just sort of understand about the risk factors that are at issue here. I mean, if a given pipeline risk model had, let's say, ten risk factors on the list, an ERW pipe, would it not be -- if you sort of weighted those, I would think your top two or three would be, as Bob said, third-party damage, corrosion and, you know -- in my experience, PHMSA has issued advisory bulletins and we have seen multiple ERW failures on all kinds of different ranges.

I would think, you know -- I think the issue is that -- the allegation is that we were missing one of the bigger higher-weighted top two or three type of risk factors, and that skewed the model that was being used. And so -- and all the operators that you guys have inspected and looked at these integrity management programs, I would think that the majority of operators with ERW would say are susceptible as part of the risk model. Is that accurate?

MR. SEELEY: I don't know that I want to draw in a generalization. I mean, to me, the information -- if I had had the information -- I think

the information would point that this pipeline would have been susceptible to the seam mechanisms that we've talked about. Having identified that will drive an operator to pursue different lines of thinking and doing different activities.

Each operator's going to have their own risk factors and threats that are going to differ from pipeline to pipeline. What your biggest threat may be is not necessarily what a different operator's threat may be. So, to try to say those universally are the worst thing in the world, I don't know that I necessarily want to state that.

It's just a point that in this allegation, there are certain basic bits of information that were present and available. And in our investigation and review of the integrity management analysis processes that you go through, we could not determine that these things were being utilized to drive the decisions within your integrity management program.

MR. WHITE: Despite the fact that test failures had occurred and --

MR. SEELEY: Well, from what we can tell, they did not utilize that information, some of the information being pipe materials, toughness, some of the information being hydrostatic test failures or

historical test failures. So, they're all bits of information that we don't see as being applied within the processes.

MS. LITTLE: On the issue of the hydrostatic test failures, I think, that's -- I mean, we've provided information on that, that the Company did, in fact, look at all those. They retained a third-party expert to look at those. That's Hurst in 2006. And that analysis, the result of it, was there was no evidence of pressure cycle-induced fatigue, selective seam corrosion or other time-dependent defects. They looked at all the failures specifically.

MR. SEELEY: That goes back to the whole --

MR. WHITE: Hardness.

MR. SEELEY: -- well toughness -- brittle versus -- we're going back to those singular mechanisms where your historical -- I think tests back before the 2005 or '6 testing, you had several in 2005 and 2006. I'm going to say 11. Prior to that, there is a test in --

MS. ATKINS: 1991.

MR. SEELEY: '91.

MS. ATKINS: Had three.

MR. SEELEY: We had three. And prior to

that, you had --

MS. ATKINS: One in 1969.

MR. SEELEY: So, you have one and three and 11. You're having a progression of these seam-related failures during testing which would mean there's something going on. There's something changing that is creating more of these throughout time. And, yet, you seem to keep falling back to the model that says they don't exist.

MS. LITTLE: They did when Hurst looked at it. And, Steve, correct me if I'm incorrect. But I believe they looked at those differences between the different hydro tests, correct?

MR. KOETTING: They did.

MS. LITTLE: And?

MR. KOETTING: One of the things that they concluded was that the pipe failures in the most recent hydro tests were due to a couple things, higher pressures than had been seen which always causes more failures, and the temperature of the test water was very low. So, it creates those brittle defects to be even more brittle.

So, their conclusions from the hydro test was that the combination of the low testing temperature and the brittle nature of those defects and the higher

test pressures would have caused the failures.

MR. SEELEY: Your temperature water being low, was it subzero? Was it freezing? There was a range.

MS. LITTLE: It was in the 40s, and the prior tests were in the 80s, 90s range. It's a significant difference.

MS. ATKINS: We took a long look at that and we also looked at your conclusions and we looked at the metallurgical analysis. And you're still in the lower shelf from zero to 95 degrees for the Charpy testing. So, all of those values were three to four regardless of temperature.

So, those statements were potential. They were not conclusions. They were considerations, and the variant testing didn't support that there was a temperature change that changed the properties because you tested the materials at zero, 35, 65 and 95 at varying different metallurgical analyses in the Charpy --

MR. KOETTING: Those are the pipes that survived, not the pipes that failed.

MS. ATKINS: Correct.

MR. KOETTING: You can't test the seams that have already failed because --

MS. ATKINS: There's no seam left.

MR. KOETTING: Destroyed, yes.

MS. ATKINS: However, there were portions of the joint that were still there but still displayed those low toughness values in a split where there was a piece left. Then they were able to test the toughness, much like what was done in this particular case.

Your statement in the current metallurgical report, which is in our Exhibit B to the violation report and the first metallurgical Number 65961 on Page 3 says, Prior to failure, the pipeline was reported to typically operate between 47 and 78. So, the 40s is still in your normal operating pressure range for the testing.

So, it's sort of unclear as to how that conclusion was drawn or if that conclusion is appropriate. And it was later questioned in the summary of the integrity results by your integrity engineers that couldn't determine whether the failure at the lower pressure was actually due to the lower temperatures or pressure reversals.

And so, there is not a conclusion that's supported either by the metallurgical testing or your own in-house documentation for that being the cause. And when you fail at a lower pressure than previously

subjected, you do have some sort of time-dependent mechanism or some sort of stress that has occurred based on what the failure looked like at the seams --

MR. KOETTING: That's true.

MS. ATKINS: -- whether it was the previous hydro testing, whether it was some sort of in-service stresses. So, there's something time dependent that's occurring.

We could probably conclude, as you did, that there was no evidence of fatigue; but all the reports qualified that the oxidation or the surface appeared to be in a manner that they could not conclude but they saw no evidence of fatigue. And from everything that we looked at, we didn't see it either because you couldn't have fatigue in that brittle material. It wouldn't -- you have to have ductile material for it to act in that manner and for the fatigue to occur.

MR. WHITE: Mary, do you have anything to add?

MS. MCDANIEL: I think Molly summarized that very well.

MS. LITTLE: Except that part of the conclusion you're drawing or based on reports that were issued post-incident and then applying it back to what

might have been known when the Company was doing the analyses at different points in time?

MS. ATKINS: Excuse me?

MS. LITTLE: Yeah. You were just talking about the most recent Hurst report.

MS. ATKINS: I'm talking about the 2005, 2006 reports, all of those Charpy values are flat, all in the three to five range for all temperatures; and it was similar to this report, the current report.

So, I was drawing a similarity. But we looked at every one of the Hurst reports from the 2005, 2006, plotted it. And the current one -- the current report is right in the middle of all the data, which is on the low end, one to three, and high end, three to five. And one of the properties is percent shear versus brittle failure, and it never got above ten percent shear on those. So, it's in the lower shelf, which means the temperature would not have made a difference for the brittleness. It was brittle in that whole range of temperatures.

MR. RANDOLPH: Let's start with the 2005, 2006 hydro test. They weren't failing at a hundred pounds or 200 pounds or 500 pounds less than the prior hydro test. It was, like, eight, eight pounds over -- since '91 or something else. That could be -- that

could be a measurement discrepancy between being used then.

MS. ATKINS: Well, you would hope not because your acceptance criteria for your pressure testing is within that range.

MR. RANDOLPH: It could have been have factored in some. It could have been less. But the point being is between '91 and 2005 and 2006, you're not seeing huge -- and then the ones that were above, say, 20, it was after that piece had already been pressured up once, and it experienced the hydro test failure. Well, then, the next one experienced the pressure reversal from that exact test. So, I think it's --

MS. ATKINS: What was the final percent SMYS that you tested in that first segment, do you recall? The successful hydro test, was it 72 percent SMYS? So, do you believe you got rid of all the cracks in that first segment?

MR. RANDOLPH: Are you talking --

MR. KOETTING: Do we believe we only had a hundred percent of the hook cracks in the pipeline?

MS. ATKINS: In that first segment. Just that first segment.

MR. KOETTING: I don't believe it's possible to remove a hundred percent of hook cracks with

a hydro test.

MS. ATKINS: Why did you accept a lower test pressure than -- on that segment instead of continuing to test to what your target pressure had been?

MR. KOETTING: The rules don't say we have to test to a certain -- pressure.

MS. ATKINS: I'm just curious.

MR. KOETTING: -- pressure. They say we have to --

MS. ATKINS: You had a plan and --

MR. KOETTING: We have to set our maximum operating pressure as a percent.

MS. ATKINS: You had a plan and a design to test to a certain level and you had four test failures in the seam and then you tested at a lower pressure.

MR. KOETTING: Yeah.

MS. ATKINS: Why -- there was a decision process.

MR. KOETTING: In any hydro test, you try to decide, are you doing good or are you doing damage during the time. If you experience pressure reversals that are significant enough -- even today when we set up a hydro test, we would consider, are we doing harm to

the pipeline by continuing to try to test it? Should we back off from it? That's a process that every operator goes through.

We don't just keep testing pipe until we destroy the whole thing. We test pipe until we get an acceptable test.

MS. ATKINS: So, would you test --

MR. KOETTING: The regulations would be really, really nice.

MR. SEELEY: I think we're sort of wandering off.

MR. KOETTING: Well, good.

MR. SEELEY: I think we've circled on the issue several times. Surprisingly, there's a disagreement on the position. I'm not going to restate it because then you'll restate it and we'll go down the conversation again. So, I think maybe any other conclusions or comments we can make in our recommendations after the hearing. And you could make yours, and we'll make ours.

MR. HOGFOSS: Just in summary, though, to respond to that one comment you made without trying to open it up again, I don't think anyone would disagree with the statement you said as a general rule if an operator concludes that there's not a susceptibility to

seam failure, then that operator might not pursue the threat it would otherwise identify. That's a pretty obvious general statement.

But in contrast, just to say again, in this instance, the operator actually did keep looking at these issues, ultimately ran a crack tool. And just a final note, that, you know, hindsight really does work both ways. Clearly we are here because there was an incident. And after the incident, the Agency took a very close look at all of these issues, the same issues that the Region did not identify as a concern in a very in-depth 2007 audit when the Company had concluded this line was not susceptible to seam failure then.

All we're saying is that we ask you in your hindsight to also look at what the Company did do. So, they did not just reach that conclusion and do nothing further. They did keep looking. They ultimately ran the crack tool. So, we're trying to stay focused on that, what can be done, what should be done, how can the Agency and the industry work together in the future on this. But I think that's it for Item 1.

MS. ATKINS: There is another potential risk that's not addressed because one of the questions in the TIARA model is is it susceptible or not. And whether you answer yes or no would create identified

threats. So, in the areas where there's seamless pipe, you wouldn't answer that yes. So, that segment of the testable -- that portion of the testable segment wouldn't have that answer.

But the risk model asks the question if it's been considered; and it, again, weights the factors that creates identified threats. So, this is one of the other risks that doesn't get identified in the identified threat process in the TIARA model.

MS. LITTLE: Which is not part of NOPV Item 1.

MS. ATKINS: It's part of considering the risk.

MR. WHITE: All right. I think that's all we have on Item 1.

MR. KOETTING: One last thing I'd like to say. The tool that we chose -- we've been criticized for choosing the tool that we chose to assess the seam. We're not in-line inspection companies. We hire in-line inspection companies to assess our pipe. The tool we chose was the tool that PII has in their crack management that's capable of identifying selected seam corrosion in ERW seam. It was the recommended tool.

MS. ATKINS: It's certainly appropriate for selective seam corrosion.

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MR. KOETTING: And ERW seam defects.

MS. ATKINS: Of a certain size.

MR. KOETTING: Regarding the best documents we had, it was the tool.

MS. ATKINS: Of a certain size, would you agree to that?

MR. KOETTING: Of a certain size --

MS. ATKINS: A specified size --

MR. KOETTING: Any defect is of a certain size. A UT crack detection tool is of a certain size. A corrosion tool is of a certain size. So, to imply that we ran the wrong tool would be to say we got the wrong guidance from our in-line inspection company.

MS. ATKINS: You ran the right tool for selective seam corrosion. You ran the right tool for a lot of things.

MR. KOETTING: Which was a higher risk.

MR. SEELEY: Okay.

MR. HOGFOSS: Actually, because this is such an important point -- and we noted it before -- but the violation report actually does say that you ran the wrong tool. You should have done the UT or an EMAT, and there isn't anything in the law to support that. There's not even any guidance out there to support that.

MS. ATKINS: The defect type and size for

the previous integrity assessments that you knew existed in the hook cracks is part of 1(i). Results of the previous integrity assessment, defect type and size. And with the crack opening widths that were in those metallurgical reports, it had not been detected because they were less than one millimeter.

MR. HOGFOSS: To quote -- to quote Rod, we disagree on that. It's not in the law. But also --

MS. ATKINS: It might be in the accident report, but I don't believe it's in the NOPV.

MR. HOGFOSS: It's not in the NOPV. It's in the --

MS. ATKINS: -- so I'm sorry.

MR. HOGFOSS: But related in that same area, though, just to note this for the record as well, because in that same area, it says clearly -- it makes this broad conclusion that the comp- -- that the Company failed to consider pipeline safety. There's a lot of statements like that, and we just would like to note for the record that we obviously strongly object to this. This is a company that does do more than the minimal required and that's a very sweeping, and we think irrelevant and absolutely completely unwarranted, statement. There's quite a few of them.

THE HEARING OFFICER: Okay. It sounds

like we've wrapped up Item 1. I know Items 2 through 4 sort of incorporate a lot of the discussion we just had. So, I think that those items will move a little bit more quickly. But why don't we try to --

MR. SEELEY: Yeah. Item 2 has to go [sic] with the reassessment interval requirement of -- there was no performance of the assessment of the line within the allocated time frame of five years, not to exceed 68 months, within the regulations.

THE HEARING OFFICER: Thanks.

MS. LITTLE: Obviously this relates back to NOPV Item 1, so without opening up that door again but just to -- because we think and it's our position that the Company did, in fact, properly assess the risks on the Pegasus Pipeline and properly did determine that the line was not seam susceptible multiple times.

We said before the Agency's had plenty of opportunities to review that and did, in fact, review it in-depth how the Company was conducting that analysis in 2007. But because the Company did determine that the line was not susceptible to longitudinal seam failure, given that conclusion, there's no requirement that a seam tool be scheduled within five years. So, the way that the IMP works, if a pipe is susceptible to seam failure, then they are required to run an assessment

tool every five years and --

MR. SEELEY: Perform an assessment.

MS. LITTLE: Thank you. Perform an assessment and then determine what the reassessment interval would be. But in this instance, because it was not required based on that seam susceptibility analysis, there was no specified time period. Therefore, there's really no five-year assessment interval to be established.

Even though, you know, the rules don't require that an operator reassess a line with a seam tool every five years, just because ERW pipe is present, you have the make the determination that it's seam susceptible. So, the Company, in compliance with the IMP regulations, reassessed the line in 2010 as part of its program within four years of the prior assessment. And the Company made a determination that they wanted to go ahead and run a seam/crack tool anyway, really consistent with the Baker report.

And frankly, the basic tenets of a program, that companies gain information, gather information, continually assess. Even the Baker report says, you know, have the best available information you can have. So, the Company wanted to run the tool to get more information on the line. And they thought it was

the prudent thing to do, and that's why they did it. But it was not subject to a five-year assessment interval.

THE HEARING OFFICER: So, just to clarify, you're not saying that there was no five-year reassessment interval. You're saying that there's no five-year reassessment interval to run the TFI tool.

MS. LITTLE: For seam --

MR. HOGFOSS: For certain -- or crack tool.

MS. LITTLE: That's right.

THE HEARING OFFICER: For running a crack tool?

MS. LITTLE: Correct.

MR. SEELEY: Yeah. I didn't hear a dispute of the particular facts of assessments, dates. I don't think we're disputing which assessments were run when. I think the disagreement is whether or not the seam assessment was required sooner than it was performed. And we would contend based of the discussion we had in Item 1 that it would have been. I don't know that there's any relevant --

MS. ATKINS: There's just one other item. That's the data integration team recommended in 2009 that in 2010 the TFI tool be run in combination with the

combo tool or the caliper or metal loss tool. And so, I don't understand what happened from then, that it was then scheduled for 2011 when the 2011 communications [sic] was changed to 2012 for budget reasons.

MS. LITTLE: Well, two things. Number one, the timing within which to conduct that tool run was actually the recommended timing was that it be run before 2013. So, it was not specified that it had to be run in 2011. And I think initially -- so, in fact, I think even under Pipelife, the way in which -- and you-all correct me if I'm wrong -- but the way in which it determines what that interval is going to be, it's really based on half-life. So, that's even very conservative to say it has to be run by 2013. So, it was well within the time that the Company had in their minds to run this tool, which they were running voluntarily anyway.

In terms of the -- in terms of the reason to extend it, I don't think it was for budget reasons. It was not for budget reasons.

MS. ATKINS: Actually it was. Just a moment and I'll find it. From 2011 to 2012, it was. But in 2009, the recommendation for 2010, I don't understand what process occurred that the recommendation from the data integration team was not taken. Is there

a process where somebody else reviews their recommendation and then decides that, no, we're not going to do it?

MS. JONES: As I recall, the recommendation from the risk and integrity specialists, it was to run the TFI tool in the first half of the line, analyze those results and then make a decision as to whether we would run it in the second half of the line. We came back in those recommendations and said, now we recommend you run it in the second half of the line.

MR. WHITE: Molly, What was your basis for bringing up the point about the budget?

MS. ATKINS: It was in the MOC.

MR. WHITE: Okay. Are you looking at one of the exhibits?

MS. ATKINS: Yeah. I'm sorry. I'll try to find it.

MR. HOGFOSS: But, again, Molly, I think the important thing is -- well, two things. One is that that's not really an alleged violation. As Rod says, I think we have a clear understanding and disagree on this point. But from the Company's perspective, the decision to run the crack tool was a management decision that was not a required run. It was a voluntary run. They were

doing more than was necessary.

So, therefore, it doesn't link to -- Rod said, we're not in disagreement. There's a obligation to do a reassessment in five years. That was being done. It was actually being done early. A separate decision as to whether or not to run a crack tool, and that was being done voluntarily. So, it wasn't subject to the timeline.

MR. WHITE: Let me just make a --

MR. HOGFOSS: That's a point of disagreement.

MR. WHITE: Let me just clarify one point about that, which is, you know, the regulation that was cited here is 195.452(J)(3); and that talks about the 68 months that was exceeded. But if you -- if you -- and in evaluating this requirement, I think it sheds light to go down to Paragraph (J)(5). (J)(5) talks about assessment methods. And 195.452(J)(5) says, quote, "An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low-frequency electric-resistance welded pipe or lapwelded pipe to susceptible longitudinal seam failure must be capable of assessing seam integrity and detecting corrosion and information anomalies."

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So, what that -- what that tells me is there's a general principle in integrity management that says you must select the tool matched to the type of risk that you're assessing. And then -- and then it goes on to specify that calls out low-frequency electric-resistence welded pipe and calls it out specifically. So --

MR. HOGFOSS: It calls it out, but it says, if deemed susceptible. The rule could say -- the rule could say all ERW pipe shall be tested with a seam and crack tool, period.

MR. KOETTING: Or hydro test on some basis.

MR. HOGFOSS: Right, at a certain level of hydro test. Or the rule could say all ERW pipe shall be replaced within -- by the following date, but it doesn't.

MR. SEELEY: That's not a recommended rule change, is it?

MR. HOGFOSS: No. Well, it is --

MR. KOETTING: Not from our side anyway.

MR. HOGFOSS: I'm just saying that the rules could say different things, but they really are -- we're dealing with the rules as they are currently.

MR. WHITE: I am as well. I am as well.

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And the second point I want to make --

MR. HOGFOSS: But the key point is deemed susceptible, and that's the point of disagreement. We did not deem it susceptible.

MR. WHITE: The second point I just want to make is what makes Item 2 separate from Item 1 is the allegation in Item 1 deals with failing to account for ERW in your overall risk model that you're using for your program. The allegation in Item 2 deals specifically with this determining the reassessment. Once the baseline has been done, that's all that's done. Item 2 deals with determining the reassessment interval, which is a sort of separate task. So, I just wanted to point that out.

MS. LITTLE: That's right. But it's a separate -- the way in which it's alleged, it's the reassessment interval after you've determined that you're susceptible to seam failure. And it's the latter part that we're in disagreement over. What the law says we're not in disagreement over. But in terms of how you establish a five-year assessment interval would be required. But what we're disputing is that the line -- we don't think the line -- we did not deem it to be susceptible to seam failure and don't think it was.

MS. ATKINS: The --

MR. SEELEY: Okay.

MS. ATKINS: -- information that I was referring to is in our violation report Appendix A-M, Appendix B and it's EMPCo Bates Stamped 017725. It's The 7/18/2000 form dated 11/15/2011. "The tool run was originally planned for the 2011 calendar year but is being rescheduled for 2012 in an effort to maintain the company's fiscal goals."

MS. JONES: And what else does that document go on to say?

MS. ATKINS: "The change in date does not cause any safety, health or environmental issues related to the pipeline segment within the Pegasus crude system."

MS. JONES: Does it not also refer to the reinspection interval that had been calculated once that decision was made?

MS. ATKINS: Well, the pipeline fatigue analysis is the one we still say that you're experiencing crack growth in a ductile manner. So, that method is one that we questioned in Item 1. So, the basis for the reassessment was using Pipelife. And we're saying that that is not the appropriate basis or --

MS. LITTLE: But the basis for the

Company's decision is that, number one, they were voluntarily choosing to run that line -- I mean, that tool. Number two, the tool needed to be run between -- needed to be run by 2013. Even that time period was established at a half-life, if you will. So, that's a conservative time frame anyway. And, yes, just as Molly noted, it goes back to the original issue for Number 1 but --

MR. SEELEY: Okay.

MS. LITTLE: -- I think we can conclude.

THE HEARING OFFICER: Anything else --

MS. LITTLE: Do we have anything else we want to add?

THE HEARING OFFICER: -- to Item 2 before we move to Item 3?

MR. SEELEY: Item 3 is probably going to carry a similar conversation. This has to do with not following procedure 5.1. This is when the operator varies from their five-year interval, they must perform certain action. And this goes back to, again, changing the assessment period for the ILI runs that we were just talking about.

THE HEARING OFFICER: Okay.

MR. HOGFOSS: And similarly, it really is the same point with Item 2. Since the Company concluded

that the pipe was not susceptible to seam failure, it was not -- it had not triggered a timeline in which to run a seam tool. There's no dispute, I think, that the Company was doing reassessments within the proper intervals. And in fact, they'd done the necessary assessment after the 2010 ILI, wasn't due until 2015. They elected -- voluntarily, not required -- to run a crack tool prior to that. But since we believe it wasn't required, it wasn't subject to a variance requirement. And I think that's really all we have to add to that.

MR. SEELEY: All right. We're done.

THE HEARING OFFICER: Item 4?

MR. SEELEY: Item 4 has to go [sic] with the prioritization of the assessments in which the operator had assessed a section -- they assessed a Patoka to Conway segment prior to the Corsicana to Conway segment even though the Patoka to Conway segment had less -- or in other words, the Corsicana to Conway segment had more risks or risk values than the other segment. So, they assessed the lower risk section prior to the higher risk section.

THE HEARING OFFICER: Okay.

MS. LITTLE: I think the important point, I guess just to step back, the IMP rules require a

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process for prioritization of segments for reassessment. They don't dictate the way the risk scores prioritization for a particular segment, but they allow operators discretion in making those determinations. So, when it comes to the Pegasus Pipeline -- and I think Muhlbauer speaks to this in his exhibit and in his affidavits in Paragraphs 11 and 12 -- the Company did consider all the risk factors and the risk conditions on the pipeline when it scheduled the 2010 reassessments.

And as we've said before, the Company's also determined that there are no segments that were seam susceptible [sic]. So, the 2007 risk scores for the two different segments were practically identical and indicated the probabilty of failure on either segment was unlikely -- very unlikely. And the decision to do the Patoka to Conway segment first -- and, Steve, and Johnita, speak up if I misspeak on this -- but was really based on four different points.

One, there were more hydrostatic seam failures on an LF-ERW per mile basis on that segment. There were more pressure reversals seen on that segment. There was a shorter theoretical fatigue life based on the existing data, and there were three girth welds [sic] that weren't present on the Conway to Corsicana segment.

And that was the basis for running the segments in the order in which they made them.

MR. KOETTING: That's true.

THE HEARING OFFICER: Anything in response to that?

MS. ATKINS: No.

MR. SEELEY: We'll save it for the recommendation.

THE HEARING OFFICER: So, that takes us to the conclusion of Items 1 through 9.

MR. SEELEY: We're not going back through 5.

MR. HOGFOSS: No. We're not going to start over with 5.

THE HEARING OFFICER: I think we've covered 1 through 9. You can't go back on that.

MR. WHITE: Sounds like this hearing may actually not have to go through lunch.

THE HEARING OFFICER: I was going to open that up to you. If we were going to talk about the penalty and the compliance order --

MR. HOGFOSS: That's relatively brief. I think if we took a short break, we can conclude it.

THE HEARING OFFICER: Okay. Let's take a short ten-minute break.

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(Recess from 11:38 a.m. to 11:50 a.m.)

THE HEARING OFFICER: We're going back on the record. We just finished concluding discussion of Items 1 through 9, and I believe there's going to be some discussion of the proposed civil penalty and the proposed compliance order. Bob, Catherine, do you want to start the discussion?

MR. HOGFOSS: Should we start instead of the Region? Do you think --

MR. SEELEY: I'll state my statement. We provide -- the process that we go through is we fill out the violation report and the enforcement office calculates a penalty based off of the information in that report. So, if your questions are related to the value or something of that nature, those are more appropriate to discuss with the enforcement office, which is now represented by Cliff on the phone.

MR. WHITE: The compliance order we can --

MR. SEELEY: The penalty part, we're just sort of a third-party here.

MR. HOGFOSS: And I don't think this will take that long, but we'll --

MS. LITTLE: Make sure he can hear you on the phone.

MR. HOGFOSS: Cliff, can you hear?

MR. ZIMMERMAN: I can hear you.

MR. HOGFOSS: All right. Good. Well, to begin and to summarize our discussion -- and this is in our pre-hearing materials as well -- as we said earlier, because there is no strict liability provision in the Pipeline Safety Act, the occurrence of an incident itself is not a basis for a violation or a penalty. We believe the Company was in compliance with applicable rules; and, thus, simply because there was an incident, we believe that there should be no violation and should be no penalty.

But in the alternative, even if a violation was deemed to have occurred, we find that the amount of penalty is unwarranted and for two reasons primarily. The first relates to the fact that several of the claims are related as in the statutory language which is picked up by the regulations at part 190 that limits a related series of violations to a combined penalty cap of no more than $1 million for incidents occurring prior to January 3rd of 2012.

And then the second reason really goes to we think there wasn't an adequate consideration of mitigation factors. To talk just for a moment about the related series of violations, this language really came in in the 2002 PIPES Amendments which really authored

the IMP amendments, regulatory [sic] as well. And there really is no legislative history to that phrase, "related series of violations," other than a snippet of discussion between Senators Kerry and Senators Hollings who stated that their understanding of what a related series of violation should mean in the Pipeline Safety Act would be to be in regard to a single incident.

Under that approach, we would think that this entire NOPV should be limited to a cap of $1 million. But beyond that, the Agency then went ahead in 2009 and for the first time addressed this issue in a decision called Colorado Interstate Gas, CIG decision, and concluded in that case that related series of violations should mean either multiple daily violations of the same requirements or where the facts in the law for multiple claims -- and this is quoting from the decision -- "are so closely related that they are not separate and should be considered one violation."

Our position is that Items 1 through 4 -- and really Items 7 and 8 based on our discussion here today -- are clearly related because they all rely on the same facts and law. The NOPV's assertion that the Company failed to consider that the segment was susceptible to seam failure really is the linchpin under each of those alleged violations, I think as

demonstrated by our discussion, that they're so nested, certainly 1 through 4; and really you need the premise of 1 to reach 7.

So, for that reason, we think that those violations clearly are related as the statute intended, as the regs intended and as the CIG decision interpreted because they do rely on the same facts and law. And, thus, they should be in combination subject to no more than a million-dollar combined penalty.

And finally we note that in the Pipeline Safety Violation Report -- we should also note -- this is in your pre-hearing materials -- it's unusual that a federal agency does not have a written penalty policy and typically a matrix that says this is how we intend to apply our statutory factors as to what the different components should be.

PHMSA in the last few years started working with the matrix of the Pipeline Safety Violation Report. Prior to that, there was really nothing. So, they picked up some of the elements; but they don't really show how they would apply as other agencies do. And there's really no guidance out there. We have been presented at a hearing with a one-page document that indicated it was a working draft of a penalty policy, but we haven't seen anything since then.

So, there's very little guidance out there other than looking at decisions as to how the Agency's statutory penalty authority should apply, but it is in the statute that the agencies should consider such factors as good faith, cooperation and mitigation. And we don't see that addressed in the violation report as mitigating factors. And we believe the record shows clearly that in this case, the Company has shown good faith in stepping up to the plate from the moment the incident occurred, working with PHMSA extensively, and will be working with PHMSA extensively. And the Company obviously has done considerable mitigation and will do more. As we discussed, they also took mitigative actions, we believe, in advance of the incident, which unfortunately failed to prevent it.

So, I think that is the summary. Catherine, anything else? Johnnie?

And in short, we think that -- we think that there should be no violations, thus, no penalty. But in the alternative, we think at a minimum Items 1 through 4 should be grouped as a related series of violations, and 7, that's really inextricable, and penalty adjusted.

THE HEARING OFFICER: Okay. Cliff or anyone else from OPS have any comments in response?

MR. SEELEY: No. I think -- we don't have any particular thing. I think we can address some of that stuff in the recommendation.

THE HEARING OFFICER: All right. Cliff?

MR. ZIMMERMAN: Yes. I couldn't hear that response.

THE HEARING OFFICER: Mr. Seeley just said that he could address some of that in his post-hearing response. I just wanted to make sure you didn't have anything else to add before we move on.

MR. ZIMMERMAN: No. I really don't at this point. We do the violation -- you know, calculate the penalty based on the evidence as presented in the violation report and the NOPV. So, that's the way we do it.

MR. WHITE: I will make one kind of quick point, which is that, you know, one of the things that has happened today, as we've sat down and we've sort of discussed the alleged violations and ExxonMobil has kind of given us their side of things, there may well -- you know -- and we have filled out the record here, in fact. There may be some mitigating points that would warrant some degree of adjustment to the penalty. So, I mean, that's the purpose for these hearings.

And so, we're not reflexively opposed to

that sort of thing. That's -- and as a matter of fact, the amount -- the proposed penalty amount for each one of these items in the notice, in the NOPV letter, is just that, it's just sort of a initial proposed kind of starting point, if you will. It fills the function of giving the operator sort of a ceiling or a cap so that it knows what the stakes are in the case.

But the -- the actual final penalty amount is not set really until the Hearing Officer produces the -- and Associate Administrator produce the final order. So, I just make the point that it's not surprising that the penalty amount initially proposed -- you know, that's based on the Agency's investigation and certain preliminary findings in the investigation. And, you know, there's nothing wrong with the fact that you've already heard today there may be some explanatory things that should also be factored in. So, just to make a point that the penalty isn't a final penalty until after this hearing process takes place.

THE HEARING OFFICER: Okay. On to the compliance order. Is there anything OPS would like to introduce in the compliance order?

MR. SEELEY: Not particularly. I don't want to read all the items. Basically there were several items that were identified obviously in the

notice. And the compliance order is basically the, A, you know, you're in violation accusation; so, B, stop being that way, through these different actions, I guess.

THE HEARING OFFICER: Okay.

MS. LITTLE: Okay. I think really just two primary points to make with respect to their proposed compliance order. The first -- Paragraph 1 of the proposed compliance order requires review and revision of ExxonMobil Pipeline Company's IMP plan for all pre-1970 ERW pipe assets of the company. And the proposed compliance order essentially, you know, is injunctive relief for the Agency. That's essentially what it stands for, corrective action that the Agency thinks an operator needs to take.

There's a lot of federal case law on the very issue of how administrative agencies develop and propose or implement their injunctive relief, how it should be -- how it should be presented. And the case law is pretty well settled that agencies should narrowly tailor their injunctive relief to the specific harm alleged, not to potential harm.

And with that sort of proposed parameters, if you will, we think that that first paragraph is too broad and extends really an incident-specific NOPV to

apply to other assets inappropriately. And it goes to some issues that we, believe it or not, haven't spent a lot of time on yet today. But this incident, this particular pipe at the failure location had unusual pipe properties and are distinct from others. And for that reason, we think it should be limited.

I think the second primary point that we want to make has to do with just a lot of the other elements on there, I guess. The IMP rules themselves, as you all know, require continual evaluation of pipeline integrity management, and that's certainly ExxonMobil Pipeline Company's obligation. And as part of that and as part of being a good operator, they're already reviewing and revising their IMP plan as appropriate based on the incident.

And so, a lot of the actions that are in the proposed compliance order to some degree are already underway. And I think that you-all -- with the exception of the Paragraph 1, I think a lot of those elements are already -- they expect that they'll be able to address all of those particular elements. But I think the bottom line is that we object to it being overly broad given the fact that the agencies are required to narrowly tailor their injunctive relief.

THE HEARING OFFICER: Okay.

MR. SEELEY: I think part of the broadness that may be here is this is dealing with your integrity management plan and things you do. And my understanding is you have a singular plan that you utilize. So, it's kind of difficult to know when you're asking for modifications to a singular plan to say but only do it for this pipeline because it becomes your plan for all of your assets by default.

So, you're kind of not able to do what you just say. Because if you modify your plan, it modifies it for the whole company, unless you're going to start creating multiple plans. I don't think that's your intent. So, it's kind of an impossibility.

MS. LITTLE: I think --

MS. ATKINS: We also had -- in looking at the annual reports for both ExxonMobil and Mobil, 80 percent of the pipeline miles are pre-70 ERW. So, it's a significant amount of the pipeline.

There have been three seam failures on the ExxonMobil assets in this region that we have investigated, and this is the fourth seam failure under this integrity management plan that has determined through the investigation and analysis conducted by ExxonMobil that it is somehow unique and an isolated event. And as such, it has kept -- that root cause

failure analysis type of decision has kept the processes from being reviewed.

So, in looking at that, the broadness that we're seeing in this region through the other ExxonMobil [sic] that we included in our discussion in Appendix B, that those conclusions continue to focus on unique isolated events instead of looking at the processes. So, that would be the broadness that would pull in -- what this plan covers is broad.

MR. HOGFOSS: If I could say a few things in response to that. First, as shown in this incident and on its entire system, the company does more than the minimally required. Thus, even if it reaches that conclusion that a segment of pipe is not seam susceptible, it's still looking at those issues. We talked about that before.

Second -- and we note this in our -- and Catherine noted it -- the Company already is -- because that's what good operators should do already is looking at what may be appropriate to revise as far as written procedures. And we understand that that -- that's part of your obligation under IMP. We don't need to wait for a final order and a compliance order on that, and I think that goes to Rod's point as well.

But, you know, to the extent -- and your

point, Molly -- to the extent that there are common issues, of course the Company's going to look at common, where appropriate, provisions. So, that process is underway. But finally, we do know -- because we've not seen that before where a compliance order -- and it may be moot as Rod says. I don't know for certain -- but where we've seen a specific incident -- pipeline then apply proposed relief to an entire company's assets. So, we do ask that that still be open for -- that we are contesting that.

And ultimately, if a final order is issued with a compliance order as it is now intact, I guess we presume that the Region, as it usually is, would be willing to discuss the timing of deadlines of certain things because some of the things are pretty crammed together in there. And one 30-day requirement may be appropriate, but then 120 days may be a short time to document everything. But we presume based on past experience that's the type of thing --

MR. SEELEY: Typically that would be addressed within the final order. There's typically an alternative to say if you need to adjust variances, you submit it. So, that's normal.

MR. HOGFOSS: And we'll raise any of those comments in our post-hearing written --

MR. SEELEY: Take our best timeline guess, and you will tell us when we're wrong.

MR. HOGFOSS: I believe -- any other -- Johnnie, anything else on that?

MR. RANDOLPH: No.

MS. JONES: No.

THE HEARING OFFICER: Anything else about not -- okay. Go ahead.

MR. WHITE: Just one sort of quick follow-up on the compliance. Catherine described it as injunctive relief. I would describe it slightly differently, which is a compliance order has only really one purpose, which is -- which is just to achieve compliance with existing code requirements.

So, for example, we couldn't put in a compliance order asking a company to go above and beyond the code requirements in the same way that, you know, somebody might think of injunctive relief as kind of a -- you know, when there's a spill as a sort of a running slate to come up with different injunctive things that somebody might think might help the situation.

So, I just want to point out that the way we use compliance orders, it's for just a limited purpose of having the Company just achieve code

compliance, nothing more and nothing less, by the way. We never do a compliance order -- we couldn't have a term in there that says you shall do something less than the code. Similarly, it's just to achieve the code and -- in the manner of having some sort of a plan and timelines and things like that.

So -- and, you know, if there is some -- if you think that there is some aspect of this particular proposed compliance order that is asking the Company to go above and beyond the code requirement, you know, you're free to sort of note that in your proposed hearing response. And then the final order that comes out may, if it -- if your -- if you are persuasive, it may adjust the compliance order for that reason. There's nothing wrong with that if that happens.

MS. ATKINS: But where there are internal processes, it's not above and beyond adherence to an existing internal process.

MR. WHITE: That's right. Rod's point still stands, that all we can do is say -- whatever plan you're using for this pipeline -- let's assume it needs to come into compliance -- the fact that the Company applies that -- the breadth and the scope to which the Company applies that plan to its other pipeline is not something that's within the government's control.

Or I could see why it would be burdensome and create different -- it would sort of go against the sort of grain of really having an internal controls, integrity management, getting away from this sort of checklist mentality and really doing risk analysis that's tailored to the pipeline, the particular risks. And most integrity compliance in my experience are sort of company-wide because you do want to have some control by the folks who are qualified and who are responsible for making those decisions.

THE HEARING OFFICER: Okay. Thank you. Before we wrap up, does anyone have anything else that they'd like to say? Otherwise, I'll just sort of cover how this case is going to proceed.

MR. HOGFOSS: Just to give a very brief, I guess, concluding statement on behalf of ExxonMobil, really as we discussed, the essence of the entire NOPV is that -- as stated in Item 1, is that the Company failed to consider the risk of seam susceptibility of ERW pipe, and we believe that the record, including the materials submitted by the Agency, shows quite the opposite, that the Company fully considered this risk thoroughly over many years and using many different methods and tools.

It's just that we didn't conclude that the

risk existed, and that seems to be the nub of the concern. And we do find that in contrast to the fact that the Agency conducted a very in-depth audit in 2007 of this precise pipeline of four inspectors for a full week. Clearly they looked at this same conclusion. The pipe was the same. The processes were the same then. So, it does seem to be an issue of hindsight post-incident.

And we, again, encourage the Agency to look not just at what they allege the Company did wrong then but also what they did right, that they did try many different ways. They didn't make that conclusion and walk away and say, we don't have to worry about ERW pipe. Instead, they took a lot of actions, including the actual running of the crack tool; and the regs don't tell you which one to use. They used a TFI tool that unfortunately did not find this defect.

And the next point is that two of the nations leading experts in both ERW pipe threat identification and pipeline risk management generally, John Kiefner, Kent Muhlbauer, agree with that conclusion. They worked with the company years ago on developing the IMP program, on developing specifically the analysis used to look at ERW pipe threat.

And they agreed both before the fact and

after the fact of this incident that this was one that you could not anticipate the probability of, and you could not detect with the current technology. And of course we mentioned that that also agrees with the Agency's own most recent statements on this entire ERW issue, that the report recently issued post-incident by the Battelle and DNV and Kiefner groups on ERW conclude even after the fact of this incident, after the allegations of this NOPV, that we're not there yet as an industry, as an Agency where we can reliably identify ERW -- all ERW defects or have management processes, including risk assessment models, that can do that.

So, the bottom line is that's where we are as a nation right now. And we don't think this company should be penalized for doing its best to work with the leading experts to pursue the issues even when they conclude they're not legally required and now after the fact to be taking a hard look of what can they do further. And in fact, that's what the Battelle -- the Agency's commissioned Battelle report recommends, saying work together, force technology. Let's try and come up with some new models. And that's what we're trying to do.

MR. WHITE: I just have a brief concluding

remark as well. You know, we agree that the integrity management regulations, you know, they are performance-based regulations and do allow for some flexibility. They're intended to allow for some flexibility and things within the operator's discretion. And each pipeline system is different, and we do want -- operators are -- it's designed for operators to do analysis and to -- in their decision-making processes.

But the regulations do have some -- I think it goes sort of too far to suggest that there's -- you know, whatever decision the operator makes, that they're all equal. I mean, the regulations do have a level of standard there that says, here are some factors that have to be analyzed. And if an operator does not analyze one of those factors, that -- you know, the Agency has to take the position that these regulations, despite the fact that they're performance-based, that they are enforceable.

And so, our position is that not every accident results in a enforcement case, which we said earlier. But, you know, a serious investigation was done in this case by experienced and qualified investigators who put in dozens and hundreds of hours of pages of documents and materials. And, you know, we don't -- we don't make -- we don't issue NOPV letters

lightly. So, it becomes -- nothing -- at least speaking for myself, nothing that I've heard today convinces me that we should just withdraw this entire NOPV. I think that based on the requirements and code and the evidence in the record, I believe they have established allegations.

THE HEARING OFFICER: Thank you. Let's talk about timing for any post-hearing submissions. Is that something you'd like to take advantage of, submitting a post-hearing brief?

MR. HOGFOSS: Yes, we would. And I just looked at the calendar and typically we look at 30 days out and that falls right on 4th of July. Could we push it to five weeks from today? Would that be okay, Johnny? That would be changing it to July 9th. Catherine's furrowing her brow.

MS. LITTLE: I am.

THE HEARING OFFICER: I was factoring a month from today would be Friday, July 11th.

MR. HOGFOSS: Probably looking at the wrong month.

THE HEARING OFFICER: Is that doable?

MS. LITTLE: I think we might need a little more time than that. 45 days?

MS. JONES: Yeah, might need a little more

time.

MS. LITTLE: 45 days. What would that put us to?

THE HEARING OFFICER: July 25th. Is that about right, I think?

MS. LITTLE: Does that sound okay?

MS. JONES: That's better.

THE HEARING OFFICER: I think that's six weeks from today.

MR. SEELEY: Birthday present for Mr. Counselor over there.

MR. RANDOLPH: Thank you.

THE HEARING OFFICER: July 25th? Okay.

Okay. I'll just recap some of the things I stated earlier. After any of the additional material is submitted to me, I'll be preparing a recommended decision which is forwarded to the Associate Administrator for Pipeline Safety who will issue the final order. In accordance with our procedural regulations, the Regional Director will be submitted a recommendation to me, which I am not bound by.

I'll give full consideration to all evidence and arguments that were presented here today and the written materials when I prepare my independent recommendation for final action.

When the final award is issued, our regulations permit the Respondent to petition for reconsideration of the final order within 20 days of receipt. That's in Section 192.43.

Any additional questions about anything before we adjourn? No? Okay. Well, we'll stand adjourned. Thank you-all for your participation today.

(Hearing adjourned at 12:19 p.m.)

* * * * *

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BEFORE THE
U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY

IN THE MATTER OF)	
)	
EXXONMOBIL PIPELINE COMPANY)	CPF NO. 4-2013-5027
PEGASUS PIPELINE INCIDENT)	NOTICE OF PROBABLE
(MARCH 29, 2013))	VIOLATION
MAYFLOWER, ARKANSAS)	

REPORTER'S CERTIFICATE

PHMSA HEARING

June 11, 2014

I, Roxanne K. Smith, the undersigned Certified Shorthand Reporter in and for the State of Texas, certify that the facts stated in the foregoing pages are true and correct.

I further certify that I am neither attorney or counsel for, related to, nor employed by any parties to the action in which this testimony is taken and, further, that I am not a relative or employee of any counsel employed by the parties hereto or financially interested in the action.

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Subscribed and sworn to under my hand and seal of office on this the 18th day of July, 2014.

Roxanne K. Smith, CSR
Texas CSR 6290
Expiration: 12/31/2012
Firm Registration No. 62
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ERRATA SHEET

PAGE LINE CHANGE REASON

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Before the
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

In the Matter of ExxonMobil Pipeline Company Pegasus Pipe Line incident (March 29, 2013), Mayflower, Arkansas	)))))))	CPF No. 4-2013-5027 Notice of Probable Violation

Index of Attached Exhibits

No.	Exhibit
1	Affidavit of John Kiefner (5/22/14)
2	Affidavit of Kent Muhlbauer (5/31/14)
3	M. Baker, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Chapter 4 & Figure 4.1 (April 2004)
4	EMPCo IMP Manual Excerpts, Sections 4.4, 5.1(4), 5.4 (2012)
5	EMPCo OIMS Framework, Elements 2.4; 7.2 (2009)
6	EMPCo OIMS System 2A, Attachment #1 Risk Matrix Methodology (rev'd 2004)
7	EMPCo TIARA Manual, Section 8.0 (2007)
8	EMPCo Memo regarding Corsicana to Patoka LSFSA (12/10/04)
9	EMPCo Memo regarding Corsicana to Patoka LSFSA (2/10/05)
10	EMPCo Management of Change Form No. 05-2829 (8/10/05)
11	EMPCo Management of Change Form No. 05-2833 (8/10/05)
12	EMPCo Hurst Metallurgical Analysis of Hydrotest Failures Excerpt Report No. 51708 (6/21/06)
13	EMPCo TIARA Foreman to Conway UDT Q&A (6/26/06)
14	EMPCo Corsicana to Patoka Summary of Hydrotest Learnings (7/06/06)
15	EMPCo Hurst Metallurgical Analysis of Hydrotest Failures Excerpt Report No. 51763 (7/06/06)
16	EMPCo IMP Integrity Assessment Data (IAD) Form 3.2 Foreman to Conway (7/26/06)
17	EMPCo TIARA Foreman to Conway Manufacturing Threat Classification (7/26/06)

No.	Exhibit
18	EMPCo TIARA Foreman to Conway Risk Assessment Summary (7/27/06)
19	EMPCo Risk Assessment Summaries: Corsicana to Foreman, Conway to Doniphan, Doniphan to Patoka (2006/2007)
20	EMPCo IMP Preventive & Mitigative Actions (P&M) Form 6.1, Foreman to Conway (2007)
21	EMPCo Foreman to Conway LSFSA and Pipelife Analysis Excerpts (2007)
22	EMPCo Patoka to Corsicana LFSA Review (2009)
23	EMPCo Email from NDT (8/23/10)
24	EMPCo NDT Preliminary ILI Report Conway to Corsicana (received 8/23/10)
25	EMPCo Repair Form PL-0751 MP 164.05 (8/28/10)
26	EMPCo IMP Exception Form 1.2 (12/17/10)
27	EMPCo Final NDT ILI Report & Repair Summary Conway to Corsicana Excerpts (2011)
28	EMPCo TIARA UDT Q&A Conway to Corsicana (2011)
29	EMPCo Conway to Corsicana LSFSA and Pipelife Excerpts (2011)
30	EMPCo Email from NDT & MP 142.39 Dig Sheet (1/10/11)
31	EMPCo Repair Form PL-0751 MP 142.39 (1/12/11)
32	EMPCo Repair Form PL-0751 MP 274.09 (1/13/11)
33	EMPCo IMP Exception Form 1.2 (1/31/11)
34	EMPCo Conway to Corsicana Manufacturing Threat Classification and Risk Assessment Summary (3/11)
35	EMPCo Conway to Coriscana IMP Form 3.2 IAD Form (3/15/11)
36	EMPCo Conway to Corsicana P&M Form 6.1 (7/21/11)
37	EMPCo Conway to Corsicana EFRD Form 6.2 (7/21/11)
38	EMPCo IMP Exception Form 1.2 (8/02/13)
39	EMPCo IMP Exception Form 1.2 (8/28/13)

Index of Exhibits Included by Reference Only

No.	Exhibit
40	EMPCo Patoka to Corsicana 2005/2006 Hydrostatic Test Reports (MP 127-437)
41	EMPCo Metallurgical Analysis performed by Hurst Report No. 40912-F (12/19/05)
42	EMPCo LSFSA Foreman to Conway and Pipelife Analysis (2006)
43	EMPCo Metallurgical Analysis performed by Hurst Report No. 41305 (4/20/06)
44	EMPCo Metallurgical Analysis performed by Hurst, Report No. 41500 (4/24/06)
45	EMPCo Metallurgical Analysis performed by Hurst Report No. 51695 (6/17/06)
46	EMPCo Metallurgical Analysis performed by Hurst Report No. 51708 (6/21/06)
47	EMPCo Metallurgical Analysis performed by Hurst Report No. 51763 (7/6/06)
48	EMPCo TIARA Foreman to Conway Risk Assessment (7/27/06)
49	EMPCo TIARA Manual (2007)
50	EMPCo Conway to Corsicana NDT MFL Combo ILI Final Report (2010)
51	EMPCo Patoka to Conway GE PII TFI Final Report (2010)
52	EMPCo LSFSA Conway to Corsicana and Pipelife Analysis (2011)
53	EMPCO IMP Manual (2012)
54	EMPCo Conway to Corsicana GE PII TFI Final Report (2013)
55	Hurst Metallurgical Investigation of Pegasus Pipeline Report No. 64961 MP 314 (7/9/13)
56	EMPCo Pegasus Root Cause Failure Analysis Final Report & Appendices (Mar. 26, 2014)

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June 11, 2014 Hearing Transcript: EMPCo Proposed Transcript Errata

Page	Line(s)	Correction
5	14	Capitalize “Office of Chief Counsel”
7	24-25	Capitalize “Associate Administrator for Pipeline Safety”
8	6	Capitalize “Regional Director”
8	16	Change “192.43” to “190.243”
12	11	Change “operate” to “cooperate”
13	10	Change “to – where appropriate” to “to, where appropriate,”
13	18	Change “Agency” to “Company”
14	9	Change “prepared” to “repaired”
14	12	Change first “report” to “reported”
14	17	Change to “Exhibits”
14	18	Change first “well” to “wall”
16	2	Change “by” to “from”
20	6	Change “fuel” to “tool”
20	7	Change “in” to “and”
20	14	Delete “,” following rule
20	17	Insert “as to” following 2001
20	23	Insert “it” following but
24	8	Changes “sides” to “sites”
32	3	Change “drying” to “drawing”
34	15	Changed “request” to “requested”
37	13	Change “got” to “sent”
37	17	Add “just” between “not __ with”
38	2	Change “get” to “meet”
42	14	Change “track” to “trap”

Page	Line(s)	Correction
44	1	Change “selected” to “selective”
44	3	Change “lead in delay” to “be delayed”
45	20	Change “track” to “trap”
49	6	Change “Is that” to “It is that”
49	10	Change “thread” to “threat”
50	23	Change “and” to “in”
54	12	No apostrophe in “questions”
56	22	Delete “the”
60	1	Change “time” to “threat”
63	6	Delete “include”
63	22	Change “not” to “but”
64	8	Add “was” between “Company ___ doing”
64	17	Add “to” before “Lake Maumelle”
69	13	Change “merge of our” to “merger of”
69	17	Change “merges” to “mergers”
71	15	Insert a quotation mark before “As”
71	18	Insert a quotation mark following “segments”
71	19	Insert a quotation mark before “”(such”
71	22	Insert a quotation mark following “segment.”
72	23	Add “and” between “corrosion” and “caliber”
72	23	Change “caliber” to “caliper”
75	20	Change “and” to “of”
75	21	No apostrophe in “changes”
78	23	Change “backward” to “back towards”
78	21	Change “clarifications” to “clarification”
80	20	Add “the” between “read ____ NOPV”
81	10	Change “incident” to “incidence”

Page	**Line(s)**	**Correction**
81	11-12	“call before you dig” should be in quotes
81	25	Change “370” to “pre-70”
82	15	Change “all the” to “oil”
82	15	Change “its” to “US”
83	20	Change “verbiage” to “verbage”
84	13	Change “if” to “is that”
84	14	Change “pipeline” to “pipeline,”
86	4	Change “regulars” to “regulations”
86	5	Change “response” to “responds”
87	10	Change “metallurgists of” to “metallurgist”
89	12	Delete “is” following well
90	6	Insert a quotation mark before “that”
90	7	Change “unique, that” to “unique, and that”
90	10	Insert a quotation mark following “industry.”
92	12	Change “affidavits talk” to “affidavits -- talk”
92	17	Add “program” after “Pipelife”
93	15-16	Insert a quotation mark before “Hydrostatic” and following “failure.”
94	16	Change “segment” to “statement”
96	11	Insert a quotation mark before “I”
96	18	Insert a quotation mark following “2013.”
97	3	Change “line’s” to “line is”
97	15	Delete the second “was” between “failure” and “susceptible”
98	11	Insert a quotation mark before “If” and change “end” to “in”
98	13	Insert a quotation mark following “susceptible.”
100	24	Change “says failures” to “says, “Failures”
101	1	Insert a quotation mark following “fatigue.” and change “continues, if” to “continues, “If”

Page	**Line(s)**	**Correction**
101	5	Insert a quotation mark following “requirements.”
103	17	Insert a quotation mark before “All”
103	20	Insert a quotation mark following “otherwise.”
103	22	Change “it” to “I”
105	12	Change “slime” to “line”
108	24	Change “seeking” to “secant”
117	14	Change “is is” to “is in”
117	18	Change “inspect to “inspected” and change “look” to “looked”
125	8	Change “huge.” to “huge pressures.”
130	21	Change “and” to “an”
131	8	Change “be the” to “be in the”
131	16	Change “pump” to “IMP”
132	4	Change “go” to “do”
132	10	Change “relate” to “relates”
135	1	Change “then” to “them”
136	8	Change “he” to “we”
137	17	Insert a quotation mark before “An”
137	24	Insert a quotation mark following “anomalies.”
139	16	Change “determine” to “determined”
140	4	Insert a quotation mark before “The”
140	7	Insert a quotation mark following “goals.”
140	8	Change “tells” to “does”
140	10	Insert a quotation mark before “The”
140	12	Insert a quotation mark following “system.”
142	25	Change “score” to “scores”
143	10	Add “failure” between “seam” and “susceptible”
143	18	Change “pro model” to “per mile”

Page	**Line(s)**	**Correction**
143	21	Add “leaks” after “girth welds”
146	22	Delete second “in” and change “Pipes” to “PIPES”
146	23	Change “regulatory” to “regulations,”
146	24	Insert a quotation mark before “related”
146	25	Insert a quotation mark following “violations,”
147	1	Change “Carey” to “Kerry”
147	14	Insert a quotation mark before “are so”
147	15	Insert a quotation mark following “violation.”
148	2	Change “aren’t” to “are”
148	5	Change “laws” to “law”
151	7	Capitalize “Associate Administrator”
154	14	Change “370” to “pre-70”
154	14	Change “models” to “miles”
155	8	Add “to” between “response” and “that”
158	19	Change “comes” to “come”
161	4	Change “DMV” to “DNV”
163	13	Change “curling” to “furrowing”
164	11-18	Capitalize “Associate Administrator for Pipeline Safety” and “Regional Director”

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Page	**Line(s)**	**Correction**
8	4	Change ñweôllò to ñwillò
11	25	Add ñanò prior to ñimmediateò
14	6	Change ñinformò to ñconfirmò
14	9	Change ñpreparedò to ñrepairedò
14	12	Change ñreportò to ñreportedò
14	14	Change ñtool lineò to ñtool runò
14	18	Change ñwellò to ñwallò
17	4	Change ñaction anomalyò to ñaction taken on the anomalyò
18	3	Change ñonò to ñofò
18	9	Change ñpressureò to ñratioò
23	8	Change ñimmediatelyò to ñimmediateò
23	12-13	Change ñto mediate that isò to ñfor immediates is thatò
26	24	Insert quotation mark after ñPage 2,ò before ñhereò and capitalize ñHereò (begin quote)
27	2	Insert quotation mark after the word ñhim.ò (end quote)
28	14	Please confirm with Ms. Jones that ñimmediate repairò should in fact be replaced with ñsafety related condition.ò I believe that was her analogy as she continues the comparison in line 18.
30	9	Change ñimmediatesò to ñimmediatelyò
39	12	Insert quotation mark (start quote) before ñourò
39	15	Insert quotation mark (end quote) after ñdays.ò
40	5	Add ñtheò before ñcareful evaluationò
40	9	Add ñonò after ñgoesò
40	12	Change ñcreateò with ñcan impactò
41	3	Change ñtrapsò to ñtrapò
41	11	Add ñwhichò before ñdoesnôtò

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Page	Line(s)	Correction
42	5	Change ñtrackò to ñtrapò
42	14	Change ñtrackò to ñtrapò
43	3	Change ñreceiveò to ñreceivedò
43	5	Change ñtrackò to ñtrapò
45	20	Change ñtrackò to ñtrapò
46	9	Change ñpoint on itò to ñpointed it outò
47	11	Change ñsomeone fromò to ñperformingò
49	10	Change ñthreadò to ñthreatò
49	24	Change ñthat itôs to performò to ñthat is to be performedò
51	8	Insert ñofò after ñcasesò
51	9	Change ñyes or no to that answer, there wereò to ñyes or no, been no for that answer then there wereò
52	9	Change ñmade andò to ñmade inò
55	15	Change ñandò to ñTIARA,ò
55	16	Change ñTIARA hasò to ñthere isò
56	6	Add ñitò before ñinò
56	16	Change ñnotò to ñnoò
56	18	Change ñknownò to ñno identifiedò
57	8	Change ñseamò to ñsameò
57	14	Insert quotation mark (start quote) before ñGoò
57	16	Insert quotation mark (end quote) after forward.ò And remove comma at end of line 16
57	16	Change ñrepresented inò to ñrepresentative ofò
57	17	Change ñwellò to ñWithò and insert a quotation (start quote) in front of ñWithò and remove comma that was after ñwellò
57	17	Remove period after yes and make ñItò ñitò
57	17	Insert ñ. . .ò after ñprobabilityò (to indicate that not all of the quote was read)
57	17	Change ñatò to ñaò
57	19	Insert end quotation mark after ñaway.ò

ExxonMobil Pipeline Company
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Page	Line(s)	Correction
60	1	Change ñtimeò to ñthreatò
60	20	Change ñmitigatedò to ñmitigativeò
64	8	Add ñisò after ñCompanyò
66	23	Delete ñinò
66	25	Add ñuntilò after ñitò
71	18	Change ñthreatò to ñthreatsò and ñimmediateò to ñintermediateò
72	8	Change ñin thatò to ñthat inò
72	23	Change ñcaliberò to ñcaliperò
80	7	Delete ñourò
84	14	Add ñhaveò after ñdidò
84	19	Change ñwhatò to ñthatò
89	17	Change ñforceò to ñenhanceò
90	3	Insert ñrootò in front of ñcauseò
90	4	Change ñthatò to ñatò
93	21	Change ñexists. Ifò to ñexists ifò
93	22	Insert ñlimitsò before ñstressò
93	23	Insert ñtoò before ñpreventò
101	10	Change ñalwaysò to ñalsoò
101	25	Insert ñproperties.ò at the end of the line
102	10	Change ñmay beò to ñmay haveò
102	24	Change ñthat is we seeò to ñthat we seeò
108	24	Change ñlog-seekingò to ñlog-secantò
110	15	Change ñwordò to ñworkò
111	10	Add ñappearò after failuresò
111	11	Change ñorò to ñofò
112	9	Change ñThatôsò to ñItôsò
112	17	Change ñfatiguedò to ñfatigueò

ExxonMobil Pipeline Company
Notice of Probable Violation No. CPF 4-2013-5027

June 11, 2014 Hearing Transcript: Suggested Corrections

Page	Line(s)	Correction
112	19	Change ñfatiguedò to ñfatigueò
115	11	Change ñourò to ñareò
122	18	Change ñofò to ñatò
126	10	Change ñWeò to ñYouò
132	4	Change ñgoò to ñdoò
132	6	Change ñupò to ñofò
135	1	Change ñthenò to ñthemò
135	3	Insert ñstate itò before was
142	12	Change ñgoò to ñdoò
154	14	Change ñmodelsò to ñmilesô
155	2	Insert ñaccidentsò before ñthatò

Before the
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

In the Matter of	)	
	)	
ExxonMobil Pipeline Company	)	CPF No. 4-2013-5027
Pegasus Pipeline incident	)	Notice of Probable Violation
(March 29, 2013), Mayflower, Arkansas	)	

RESPONDENT'S
POST HEARING BRIEF

INTRODUCTION

As drafted, the Notice of Probable Violation (NOPV) issued to ExxonMobil Pipeline Company (Respondent or Company) implies that violations must have occurred because there was an incident. The Pipeline Safety Act (PSA) has no strict liability provision, however, a fact that was admitted by the Pipeline and Hazardous Materials Administration (PHMSA or Agency) at the Hearing. The Agency must therefore prove alleged violations, not presume them. The Agency has not established that proof in this case.

I. The Law Applicable to LF-ERW Pipe

In order to fully evaluate the allegations made by PHMSA in this matter, particularly for NOPV Items 1-4 and 7, it is necessary to understand the state of the law underlying integrity management regulation of low frequency electric resistance welded (LF-ERW) pipe. The National Transportation Safety Board (NTSB), PHMSA and leading experts in pipeline metallurgy and risk management nationally have not yet been able to develop a standard process that allows operators to identify all features associated with the risk of seam failure on LF-ERW pipe, because current technology does not provide adequate data to identify all ERW anomalies. The NOPV in this matter, however, flatly asserts that Respondent had "*more than adequate information*" to be able to do just that. *NOPV Item 1, p. 2.* That assertion is simply wrong. The Agency itself has not been able to produce rules or guidance that would direct operators to find such isolated anomalies, and the leading experts in this area – both Respondent's and the government's – have concluded that technology is not yet capable of finding all these anomalies.

Various methods have been used over the decades to manufacture steel pipe used in construction of oil and gas pipelines. One of the methods used prior to 1970 involved joining the long seam of pipe segments by LF-ERW. In 1986, two long seam failures of pre-1970 LF-ERW pipe occurred in Minnesota, leading the Office of Pipeline Safety (OPS) to issue alerts to industry in both 1988 and 1989. *Exhibit 72, OPS Alert ALN-88-01 (Jan. 28, 1988); Exhibit 73, OPS Alert ALN-89-01 (Mar. 8, 1989).* The alerts simply warned that LF-ERW welds had the potential to fail in limited circumstances, and that operators should consider that potential risk while conducting pipe inspection and maintenance activities.

In 1994, and again in 2000 (in the integrity management program (IMP) rule), OPS issued rules directing liquid pipeline operators to conduct hydrostatic pressure testing of pre-1970 LF-ERW pipe in certain circumstances. *Exhibit 74, Final Rule, 59 Fed. Reg. 29379 (June 7, 1994)*; *Exhibit 75, Final Rule, 65 Fed. Reg. 75378 (Dec. 1, 2000).* The Agency also commissioned a study resulting in a report issued in 2004, proposing a protocol for operators to use in evaluating the risk posed by pre-1970 LF-ERW pipe. *Hearing Exhibit No. 3 (Baker-Kiefner Report).* The protocol it proposed was not incorporated into OPS rules, but operators were encouraged to follow it. Respondent not only followed that protocol, it retained one of the study co-authors (John Kiefner) to help adapt the protocol specifically to the Company's IMP.

The OPS rules regarding pre-1970 LF-ERW pipe for liquid lines are minimal, and more advisory than prescriptive. In fact, there are only three places in the entirety of Part 195 that address pre-1970 LF-ERW pipe: 49 C.F.R. Part 195.303(d) (which was a one-time opportunity to conduct

risk based alternatives to hydrotesting); and Parts 195.452(e)(1)(ii) (requiring consideration of manufacturing information as a risk factor in IMP threat identification) and 195.452(j)(5) (requiring assessment methods for LF-ERW pipe susceptible to seam failure to be capable of assessing seam integrity, among other things). Where a segment is found to be susceptible to longitudinal seam failure under the IMP rules, an operator is directed to use certain integrity assessment tools. Other than the requirement to "consider" the risk of ERW seam failure, however, the Agency has offered no specific guidance to operators beyond the non-mandatory 2004 Baker-Kiefner report.

In 2007, a pipeline accident in Carmichael, Mississippi involving LF-ERW pipe led the NTSB to issue two formal recommendations to OPS (by then part of PHMSA). Recommendation P-09-01 urged PHMSA to "conduct a comprehensive study to identify actions that can be implemented by pipeline operators to eliminate catastrophic longitudinal seam failures in electric resistance welded (ERW) pipe." *Exhibit 68, NTSB Accident Report, NTSB/PAR-09/01, at p. 51 (Nov. 1, 2007).* Recommendation P-09-02 encouraged PHMSA to "implement actions needed [based on the results of the study requested in P-09-01]." *Id.* NTSB stated that its reason for making such recommendations was a conclusion that "*[PHMSA's] current inspection and testing programs are not sufficiently reliable to identify features associated with longitudinal seam failures of ERW pipe prior to catastrophic failure*" of an operating pipeline. *Exhibit 69, Letter from NTSB to PHMSA, at p. 3 (Oct. 27, 2009), transmitting recommendations* (emphasis added).

NTSB's recommendations to PHMSA regarding LF-ERW pipe went unaddressed for several years. The NTSB issued letters to the Agency in 2010, 2011 and 2012, inquiring about the status of PHMSA's response on the issue. In the 2010 letter from NTSB Chair Deborah Hersmann to PHMSA Administrator Cynthia Quarterman, NTSB stated that it was "disappointed" that PHMSA had not yet commenced a study on LF-ERW pipe. *Exhibit 70, Letter from NTSB to PHMSA, at p. 1 (Dec. 29, 2010).* In a subsequent letter, NTSB noted that it understood the Agency finally had commissioned the ERW study, which was expected to be completed by the Battelle Memorial Institute by November 2012. *Exhibit 71, Letter from NTSB to PHMSA, at p. 2 (Oct. 19, 2011).*

It was not until five years after the NTSB issued Recommendations P-09-01 and P-09-01 to PHMSA about LF-ERW pipe that Battelle issued an interim report." *Exhibit 65, Battelle Institute, "Final Interim Report" on ERW Seam Failures (Sept. 20, 2012) (Battelle Interim Report).* A little more than a year after that, Battelle issued a "Final Summary Report," dated October 23, 2013. Significantly, this "Final Summary" report was issued after the Mayflower incident. The October 2013 report commissioned by PHMSA noted that:

> …it is clear that gaps remain both in the understanding of the [ERW] failure process, and in quantifying the effectiveness of current schemes and technology to manage the ERW pipeline network. As such, the work initiated under [this study project] is being continued to bridge those gaps.

Exhibit 66, Battelle Final Summary Report on ERW Seam Failures, p. vi (Oct. 23, 2013) (Battelle Final Summary Report).

The Battelle study commissioned by PHMSA is still ongoing, long after NTSB issued its Recommendations on point, and long after the Mayflower incident that is the subject of this NOPV. On May 31, 2014, Battelle issued its "12th Quarterly Report" on the continuing work on this issue. That update notes that 15 Task Reports have been issued under Phase I of the project, but that the stated goal of the study has not yet been met: "to identify the factors the pipeline operators must consider in order to assure that their ERW pipelines are safe." *Exhibit 67, Battelle ERW Study, 12th Quarterly Report,* p. 1, "Public Page" (May 31, 2014).

Battelle's reports note that the frequency of occurrence of long seam weld failures on LF-ERW pipe has been declining since the 1960s. *Exhibit 65, Battelle Interim Report p. 76 (Sept. 20, 2012).* That trend is obviously important, as more than 25% of all liquid pipelines in the U.S. contain pre-1970 ERW pipe. *PHMSA, Hazardous Liquid Annual Data 2012 (as of May 1, 2014) available at* www.phmsa.dot.gov (includes direct current welded pipe). If the risk of seam failure was greater than it is, PHMSA could direct more mandatory inspection or testing activities than it has. To the credit of NTSB and PHMSA, however, study of this risk continues, with a goal of providing pipeline operators with better tools and methods to predict and identify LF-ERW long seam anomalies that could otherwise lead to failure in limited circumstances.

As discussed below, Respondent complied with all applicable law and guidance in evaluating the Pegasus Pipeline for susceptibility to long seam failure of LF-ERW pipe. Post-incident analysis confirmed that the anomaly was not capable of reliable detection. In sum, more than five years of vigorous study and analysis by PHMSA to develop actions that could be implemented by pipeline operators to eliminate LF-ERW failures has offered no definitive results or guidance, yet PHMSA's NOPV directly faults Respondent for not completely eliminating the possibility of a LF-ERW seam failure on a pipeline that operated for over 60 years without incident. The Battelle study on ERW issues, commissioned by PHMSA, continues, but its preliminary findings support the Company's position in this proceeding.

II. Respondent Complied with the Law Applicable to LF-ERW Pipe with an IMP Plan, Engineering Analyses on Seam Risk, ILIs and Hydrotests (NOPV Items 1-4, 7)

A. Overview of Relevant NOPV Allegations

In NOPV Items 1 – 4 and 7, PHMSA asserts five violations of its IMP regulations concerning LF-ERW pipe. PHMSA specifically alleges that Respondent failed to (1) consider the susceptibility of pre-1970 LF-ERW pipe seam failure as a risk factor when establishing its assessment schedule, citing 49 C.F.R. Part 195.452(e)(1) *(NOPV Item 1)*; (2) establish a five year reassessment interval, citing Part 195.452(j)(3) *(NOPV Item 2)*; (3) obtain a variance from the five year interval to extend the seam/crack tool assessment of Conway to Corsicana in violation of its procedures (IMP Plan 5.1), citing Part 195.452(b)(5), (j)(4) and (i) *(NOPV Item 3)*; (4) prioritize higher risk segments of the Pegasus Pipeline for reassessment, citing 195.452(e) and (j)(3) *(NOPV Item 4);* and (5) follow internal procedures (IMP Plan 5.4 and OIMS 2.4) by not updating its risk assessment when the TFI tool run was delayed, citing 49 C.F.R. Part 195.452(b)(5) and (j)(1) and (2) *(NOPV Item 7).*

All of these allegations hinge on PHMSA's presumption, conveniently made after the fact, that the Pegasus Pipeline should have been determined to be susceptible to seam failure.

All of these allegations, however, are unsupported by the facts, the law and available guidance. The allegations and their underlying presumption also conflict with the opinions of the nation's leading experts on these issues.

B. Respondent Appropriately Conducted Seam Susceptibility Analyses and Pressure Testing of LF-ERW Pipe

As discussed in Section I, above, other than alerting operators to the potential risk of seam failure on some LF-ERW pipe, PHMSA has provided little regulation or guidance on how to anticipate or locate LF-ERW anomalies. The most recent research into these issues was commissioned by PHMSA and conducted by Battelle, which concluded (notably, after the Mayflower incident) that technology and methods are not yet well enough developed to be able to identify all LF-ERW anomalies, even as the occurrence of LF-ERW related incidents is declining. The record in this case shows that Respondent did *far more* than required by existing rules or guidance to identify LF-ERW pipe that is susceptible to seam failure.

Respondent incorporated LF-ERW consideration procedures into its IMP program from the very outset, using the services of one of the co-authors PHMSA retained to develop guidance on the topic. The Company carefully considered all relevant risk factors, based on all available information, in establishing its baseline and reassessment schedules. Respondent subsequently completed four separate engineering analyses specific to the Pegasus Pipeline, looking at the risk of seam failure and incorporating information from three hydrostatic pressure tests and three in-line inspection (ILI) runs (one with a crack/seam tool).

John Kiefner, who co-authored the 2004 LF-ERW seam failure risk study commissioned by PHMSA, and who was part of the 2012/2013 Battelle study commissioned by PHMSA to further examine ERW risk, has submitted an affidavit for this matter. As stated clearly in his affidavit, hydrostatic test failures alone are not indicative of susceptibility to seam failure. *Hearing Exhibit No. 1, Kiefner Aff. ¶ 13*. There must be evidence of fatigue-related failures, selective seam corrosion or other time dependent defects (such as stress corrosion cracking). *Id.* Kiefner goes on to describe his review of the data associated with the Mayflower incident, noting that the "point of failure showed no evidence of fatigue." *Id. at ¶ 17.* More significantly, Kiefner concludes that

> [he has] reviewed the integrity data that would have been available to EMPCo prior the incident regarding the Conway to Corsicana testable segment. Based upon that review, EMPCo's conclusion that the segment was not seam-failure-susceptible under the federal regulations was reasonable, and was consistent with the seam failure susceptibility determination guidance available prior to March 29, 2013.

Id. at ¶ 19. Kent Muhlbauer, a national pipeline risk management expert who has also worked with PHMSA, also submitted an affidavit stating that

> It is my opinion that the Company properly recognized the issues associated with LF-ERW pipe, reacted to the threats on the Pegasus Pipeline, and complied with the Part 195 IMP regulations.

Hearing Exhibit No. 2, Muhlbauer Aff. at ¶ 11.

At the Hearing, PHMSA raised additional issues concerning Respondent's methods and analyses used to evaluate seam risk, suggesting that the Company did not sufficiently consider that the pipe was brittle, and therefore the continued focus on fatigue analysis was misplaced. PHMSA asserted that Respondent should have focused on the hardness and toughness of the pipe in its analyses. *Transcript of Hearing on PHMSA NOPV CPF 4-2013-5027 (Jun. 11, 2014) (Transcript), p. 111, lines 1-9.*

The Company's detailed seam susceptibility and fatigue analyses expressly considered all available information regarding the Pegasus Pipeline, including its manufacturing history, the pipe material properties (such as documented fracture toughness values), sixty years of operating and maintenance history, leak history, and the results of prior pressure tests and integrity assessments (and subsequent metallurgical analysis). In the absence of evidence of other failure mechanisms on the Pegasus Pipeline, including pressure reversals, environmental cracking, and hardness related to the seam, the Company relied on the Baker-Kiefner process which directs an operator to analyze pressure cycle-induced fatigue.[1] Indeed, the Company directly consulted with John Kiefner, one of the world's leading experts on LF-ERW seam failure analysis. Contrary to PHMSA's allegations at the Hearing, Respondent's Pipelife fatigue analysis software (developed by John Kiefner) specifically considers toughness (*i.e.*, the measure of a pipe's brittleness) as a factor in the analysis, and the Company followed the manual's instruction to use actual representative toughness values when they are available.[2]

In addition, at the Hearing, PHMSA asserted that Respondent should have run its hydrotests at higher pressures, from 90-100% SMYS, in order to properly assess seam risks or threats. *Transcript, p. 105, lines 8-15.* The Agency's regulations do not specify any such pressures or hydrotest parameters for LF-ERW pipe beyond compliance with Subpart E, however.[3] To that very point, Kiefner noted in his affidavit that "the level of hydrostatic test

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[1] As attested to by Kiefner, the Company's conclusion that the segment was not seam failure susceptible was "reasonable" and "consistent with available guidance," further based on the examinations of the prior hydrostatic test failures, there was "no evidence of excessively hard heat affected zones." *Hearing Exhibit No. 1, Kiefner Aff. ¶¶ 18, 19.*

[2] The 2011 analysis used a seam toughness CVN value of 7 because it was the average representative toughness value documented by the Hurst 2006-2007 analyses of the 2005-2006 hydrotest failures. Further, Kiefner notes that his review of the pipe material properties indicates that the anomaly that caused the Pegasus incident "was not capable of reliable detection given that it exhibited atypical characteristics not frequently seen before in the industry." *Hearing Exhibit No. 1, Kiefner Aff. ¶ 24.*

[3] This issue was raised at the Hearing and Respondent pointed out that there are no Agency regulations or guidance that require a higher hydrostatic test pressure for this type of pipe. *Transcript, p. 105, lines 17-18.* While PHMSA suggested that 49 C.F.R. Part 195.303(d) has bearing on this issue, as explained by Respondent at the Hearing – and notably not challenged by PHMSA – that provision was enacted in 1998 and established a one-time historical opportunity for operators to elect a risk-based alternative to pressure testing of pre-1970 pipe, and specifically at subsection (d) for pre-1970 LF-ERW pipe. *Transcript, p. 105, line 16 – p. 106, line 11.* That provision was enacted prior to the IMP rules, and other than specifying considerations for seam susceptibility analyses, it has no other relevance. *Id.* Further, 195.303(d) required pressure testing of pre-1970 LF-ERW pipe that was susceptible to seam

pressure employed in 2006 on the Conway to Corsicana segment was consistent with the 49 C.F.R. Part 195 regulatory requirements." *Hearing Exhibit No. 1, Kiefner Aff. ¶ 22.*

Even after its conclusion that the Pegasus Pipeline was not susceptible to seam failure, and despite the lack of direction or guidance from the Agency, the Company continued to conduct tests and analyses, using both company engineers and third parties, to reevaluate whether the line was susceptible.[4] No actionable anomaly was ever identified on the segment of pipe that failed in the Mayflower incident. Significantly, even after the incident, metallurgical examination revealed a pipe joint with highly unusual chemical and mechanical properties and unique characteristics at the point of failure. *Hearing Exhibit No. 1, Kiefner Aff. ¶¶ 16, 17.* There is no evidence that the anomaly that failed was capable of reliable detection by technology and methods of inspection used at the time in compliance with applicable law.

The Agency conducted an intensive inspection of the Company's IMP program and LF-ERW procedures in 2007, specifically with respect to the Pegasus Pipeline, and found no issue with those procedures or their implementation. The record shows that Respondent complied with all of PHMSA's existing rules and guidance in trying to anticipate and identify LF-ERW seam susceptibility issues on the Pegasus Pipeline. *Hearing Exhibit No. 1, Kiefner Aff. ¶ 21* ("The seam-integrity assessment activities that EMPCo employed on this segment of pipe were consistent with the Baker Report Flow Chart and IMP regulations and guidance in effect at the time.").

C. Respondent Complied with Applicable Law and Guidance in Conducting ILI of the Pegasus Pipeline

Given all available information and analyses, conducted over a period of time, Respondent concluded that the Pegasus Pipeline was not susceptible to seam failure. Despite that conclusion, the Company elected to voluntarily run a seam/crack tool in 2012. The next reassessment after the 2010 ILI on the Conway to Corsicana segment was not due until 2015, but the Company voluntarily decided to employ the seam/crack tool well in advance of that date.

Because a seam/crack tool was not required, it was not subject to the variance reporting requirements under the IMP rules or the Company's IMP procedures, as alleged in NOPV Item 3. The Company's IMP Manual Section 5.1 incorporates verbatim the language of Part 195.452(j)(3), which requires an operator to request a variance when it cannot meet the 5 year interval. The rules do <u>not</u> require an operator who *voluntarily* elects to reassess a line with a seam tool, however, to request a variance.

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failure pursuant to pressure levels under Part 195 Subpart E pressure test which is consistent with the pressure test that Respondent performed in 2006 on the Pegasus Pipeline.

[4] Although not directly relevant to the allegations set forth in the NOPV, at the Hearing and in the Agency's Pipeline Safety Violation Report (PSVR), PHMSA suggests that the Company has not updated its LF-ERW susceptibility analysis in light of a 2012 incident in Torbert, Louisiana or participated in industry research regarding these issues. These statements are inaccurate and not germane to this proceeding.

Similarly, since the decision to run a seam/crack tool was not required under IMP, it was not therefore subject to the prioritization process at the base of NOPV Item 4. Contrary to the Agency's allegations in support of Item 4, the decision to run Patoka to Conway segment first was based on an analysis that the Patoka to Conway segment experienced (i) more hydrostatic seam failures on a LF-ERW per mile basis; (ii) more pressure reversals; (iii) shorter theoretical fatigue life based on existing data; and (iv) three girth weld leaks not present in Conway to Corsicana. Also, in the same year, the Company assessed the Conway to Corsicana segment with a magnetic flux leakage combo ILI tool.

For the foregoing reasons, Items 1 – 4 of the NOPV should be dismissed or rejected because they are neither supported by the law or facts, and they are all based on an incorrect after-the-fact presumption: that the Company should have deemed the Pegasus Pipeline susceptible to seam failure. PHMSA goes on to allege in Item 7 of the NOPV that Respondent failed to consider preventative and mitigative (P&M) measures (as incorporated into the Company's internal procedures), by not updating its risk assessment when the voluntary TFI tool run was delayed. As reflected by the record, that allegation is simply incorrect. The Company revised its seam failure susceptibility analysis risk assessment in March of 2011, and it was scheduled to be reviewed again in 2013. The re-assessment interval was conservative and no changes had occurred that would affect the assessment. Further, no TFI seam/crack tool run was even required, since all prior risk assessments had concluded that there was no risk of long seam failure. Simple logic underscores how this alleged violation is without support, given that no anomaly was reported when the Company ultimately did run the TFI tool in 2012-2013; since crack growth is typically a time dependent threat, it was even less likely that any anomaly would have been discovered by an earlier tool run, as suggested by the allegations in Item 7.

NOPV allegations 1 - 4 and 7, all of which rely upon PHMSA's presumption that the Pegasus Pipeline should have been determined to be susceptible to seam failure, are unsupported by the facts, the law and available guidance. They also conflict with the opinions of the nation's leading experts on these issues. The record in this case clearly shows that Respondent did *far more* than required by existing rules or guidance to identify LF-ERW pipe that is susceptible to seam failure. In establishing its assessment schedules, the Company carefully considered all required risk factors based on all available information, expressly including risks associated with LF-ERW pipe. The Company subsequently completed four separate engineering analyses to further evaluate the risk of seam failure on the Pegasus Pipeline, incorporating information from three hydrostatic pressure tests and three in-line inspection (ILI) runs (one with a crack/seam tool). Each analysis indicated that the line was not seam failure susceptible and the Company performed its integrity assessments and evaluations accordingly and in compliance with the IMP regulations and its internal procedures.

III. PHMSA Has Not Proved Alleged Violations Nos. 5-6 or Nos. 8-9

A. NOPV Item 5

PHMSA alleges that two locations, "MP 164.051" and "MP 142.394," were identified as immediate repair conditions on a preliminary report from the tool vendor that was received by Respondent on August 9, 2010. PHMSA asserts that instead of considering this information as

presenting "immediate" conditions, Respondent instead treated the anomalies as confirmation or validation digs, and that the Company did not declare them as "immediates" until the sites were excavated. As a result, PHMSA asserted at the Hearing that Respondent was "declaring discovery in the ditch" and failed to take appropriate actions for "immediate conditions" pursuant to 49 C.F.R. Part 195.452(h). *Transcript, p. 22, line 22.* To the contrary, as set forth in the Pre-Hearing Brief and stated in the Hearing, both of these allegations are incorrect as a matter of fact and law, because: (1) the vendor reports were received on August 23, 2010, and January 10, 2011, respectively; and (2) in both instances, the Company took prompt action to efficiently and effectively remediate the anomalies, in accordance with its IMP procedures that have been reviewed and inspected by PHMSA numerous times.

The first anomaly at Site MP 164.051 was not identified as an immediate condition because it was estimated to be a 72% wall loss anomaly on the preliminary vendor report that was provided to Respondent on August 23, 2010.[5] *Hearing Exhibits No. 23 and 24*. Such an anomaly is not classified as an "immediate" condition unless and until it is greater than 80% wall loss. *49 C.F.R. Part 195.452(h)(4)(i)(A).* The Company added tool tolerance, in accordance with its internal procedures that exceed the regulatory requirements. *Transcript, p. 29, lines 12-23; Exhibit 57, Respondent's IMP Manual, Appendix K, Validation and Repair Process (2010).*[6] As a result, the Company promptly took action by declaring the anomaly as a potential "immediate" on the same day and excavated, examined and repaired it within five days. *Hearing Exhibit No. 25*.[7] As further explained by Respondent at the Hearing,

> Our program makes an analogy between an <u>*unvalidated*</u> preliminary report and an immediate repair and a safety related condition. So, we have five days to validate that report and then five days to fix it. And so, we immediately convene a discussion internally when we receive that report and begin to take those steps as if it were a safety [related] condition. So, we repaired it within that very first five days.

[5] The NOPV erroneously states Respondent received the preliminary report on August 9, 2010, but that is a reference from the vendor's database, <u>not</u> the date information was transmitted to Respondent. PHMSA stated at the Hearing that this was "the first time [they had] seen that [date]." *Transcript, p. 26, lines 19-20.* That statement is simply unsupported by both the NOPV itself and further discussion at the Hearing. PHMSA cites to the correct receipt in NOPV Item 6 where the correct receipt date of August 23, 2010, is set forth in the Table at p. 6 of the NOPV, last line, second column. PHMSA attempted to suggest in the Hearing that the data must have been available on August 9, 2010, due to the wording by the vendor in an August 23, 2010, email attached as Hearing Exhibit 23 that "Today is the day [Respondent] wanted [the data] sent to him." *Transcript, p. 18, line 3.* To the contrary, this is simply a reference to the fact that the data was due to be provided to the Company on August 23, 2010, consistent with Respondent's requirements that the vendor provide preliminary reports within 30 days of completion of the 2010 Conway to Corsicana ILI. To suggest otherwise is pure conjecture on the part of the Agency without any factual basis whatsoever.

[6] Notably, this specific procedure has been inspected many times by PHMSA and the Agency has not cited any concerns.

[7] In this instance, the anomaly did, in fact, turn out to be an immediate with greater than 90% wall loss. *Transcript, p. 29, lines 12-19.*

Transcript, p. 28, lines 11-19 (emphasis added); *Exhibit 58, Respondent's IMP Manual, Section 2.3.5.4.2-4 (Safety-Related Condition Requirements) (2010).* In PHMSA guidance, the Agency endorses consideration of safety-related conditions as they relate to immediate repairs.[8] Further, PHMSA guidance expressly provides for the discovery of immediates upon excavation and examination. *Exhibit 79, PHMSA Liquid IMP Frequently Asked Question (FAQ) 7.19*.

The second anomaly referenced in the NOPV as Site MP 142.394 was not included in the August 23, 2010, preliminary report at all, but instead was called out in the final report from the vendor that was received by Respondent on January 10, 2011.[9] *Hearing Exhibit No. 30.* Respondent determined that this anomaly was an immediate condition based on orientation and proximity to a high consequence area. As reflected in Hearing Exhibit 31 and related documentation, the Company immediately scheduled the anomaly for excavation, made relevant one call notifications, and repaired the anomaly two days later, on January 12, 2011, when it was excavated.[10]

NOPV Item 5 should be dismissed for failure to state a claim given that PHMSA has not produced evidence in support of either allegation regarding the anomalies in question, and Respondent fully complied with the IMP rules and procedures.

B. NOPV Item 6

PHMSA cites four occasions where Respondent allegedly failed to declare discovery of actionable anomalies within 180 days of an ILI assessment, per 49 C.F.R. Part 195.452(h)(2), "despite the availability of adequate information in the vendor reports to make such determinations." The Agency is incorrect as a matter of fact and law. In all four instances, the Company did not receive ILI data from the vendor until near the end of the requisite 180-day period. As a result, in all four instances, adequate information was <u>not</u> available and 'discovery' was impractical given the late transmittal of data. PHMSA's IMP regulations and guidance allow for situations where vendor data is received so late as to make declarations of "discovery" within that time period impracticable. *49 C.F.R. Part 195.452(h)(2).*

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[8] *See e.g., Exhibit 80, Notice of Amendment in re: Cenex Pipeline Company, CPF 5-2011-5018M (July 26, 2011)* (citing an operator under 49 C.F.R. Part 195.452(h) for failure to reference its safety-related condition report procedure in its IMP manual related to immediate conditions to require a safety-related condition report where a repair cannot be made within 5 days of determination or 10 days of discovery).

[9] This is a different anomaly than cited to in the Agency's PSVR, and at the Hearing PHMSA further confused the issue by citing to other anomalies that are not alleged in the NOPV. *Hearing Exhibit No. 32; Transcript p. 21, lines 23 – p. 22, line 17.* The NOPV clearly alleges a violation with respect to an anomaly at MP 142.394, however; given that is the specific allegation at issue, any discussion at the Hearing regarding other anomalies is simply irrelevant.

[10] Respondent has confirmed that page 3 of the PL-0751 form mistakenly identifies January 5, 2011, as the discovery and repair date. Related documentation supports that the final report was received on January 10, 2011, and that the repair occurred on January 12, 2011. *See Hearing Exhibit No. 31* (repair form signed Jan. 12, 2011; attached dig sheets printed on Jan. 10, 2011); *Hearing Exhibit No. 27* (final ILI report and repair summary noting receipt on Jan. 10, 2011 and repair on Jan. 12, 2011)*; Hearing Exhibit 30* (email correspondence regarding the final report dated Jan. 10, 2011); *see also Exhibit 59, Email from C. Gorman dated Jan. 10, 2011* (noting that date as day zero for the potential immediate).

At the Hearing, PHMSA asserted additional allegations not reflected in the NOPV, namely that, because the Company requested that the vendor provide data for four segments together, the vendor could not have met the 180-day deadline because of the length of the entire tool run. *Transcript, p. 39, lines 8-16, 25- p. 40, line 1*. PHMSA asserted that an operator must account for both its process and the final vendor report within the 180-day period, and that an operator cannot use the fact that a vendor provided data late in the 180-day period as the basis for an impracticability argument. *Transcript, p. 35, lines 12- p. 36, line 2.*

No Agency regulation, guidance or precedent exists that governs the particular length of a tool run in the IMP regulations. There is also little guidance on impracticability, but PHMSA has held in other cases that there are "…situations where a delay in receiving ILI results from a tool vendor may render the 180-day discovery period impracticable." *Exhibit 78, Final Order in re ExxonMobil Pipeline Company, CPF 4-2011-5016, (June 27, 2013), p. 17.*

Respondent has clearly demonstrated in the record that, in all four instances cited by PHMSA, the tool vendor did not provide the Company with the ILI data until very nearly the end of the 180-day period. This is despite express commitments by the vendor to provide preliminary data within 30 days and final data within 90 days of completion of any ILI tool run, in order to allow the Company sufficient time to validate and integrate the data within the regulatory timeframe.[11] In light of the late dates in which the final data was received, it was simply not possible to verify the ILI vendor data and to conduct data integration properly. PHMSA's assertion that the Company knew that the vendor would not be able to provide the final data within 180 days is inaccurate and not supported by the evidence.[12] As allowed by the IMP rules, Agency guidance and the Company's IMP procedures, the 180-day period was extended for acknowledged reasons, and documented in accordance with the Company's IMP Plan and the IMP regulations. *See Hearing Figure 4 and Exhibits No. 26, 33, 38 and 39* (IMP Forms 1.2 documenting each extension).

Given the lack of regulation or guidance that supports either of PHMSA's allegations in this instance, NOPV Item 6 should be withdrawn in its entirety, or alternatively, the penalty should be substantially reduced.

C. NOPV Item 8

The NOPV alleges that Respondent violated 49 C.F.R. Part 195.402(a) regarding operations and maintenance (O&M) manuals, but as noted at the Hearing, the actual allegations and facts relate to the Agency's IMP rules under Part 195.452. *Transcript, p. 63, lines 12-16*. In addition to the fact that this allegation is erroneously pleaded as a matter of law, it also fails on

[11] Specific only to the last of the four tool runs at issue, the 2013 Conway to Coriscana TFI tool run, the ILI vendor subsequently committed to providing the preliminary data within 60 days and the final data within 90-120 days. *See e.g., Exhibit 64, Email from J. Johnson (GEPII) to P. Vocke (Respondent) (April 12, 2012).*

[12] *See e.g., Exhibit 61, Email from L. Lamons (Respondent) to J. Johnson (GE PII) (Nov. 29, 2012); Exhibit 62, Email from C. Gorman (Respondent) to R. Coryell (GE PII) (Dec. 3, 2012); Exhibit 63, Email from C. Gorman (Respondent) to B. Hagerman (GE PII) (Mar. 15, 2013).*

the merits because Respondent did comply with the relevant integrity management regulations and its procedures.

PHMSA alleges under NOPV Item 8 that Respondent violated O&M provision 49 C.F.R. Part 195.402(a) by selectively using its IMP threat identification and risk assessment (TIARA) process in violation of its IMP manual (which resulted in the failure to characterize the risk of a release to certain areas). The regulation cited, 49 C.F.R. Part 195.402(a), however, is wholly unrelated to the allegations, which instead are founded on the IMP rules at 49 C.F.R. Part 195.452. *See 49 C.F.R. Part 195.402(a)* (requiring operators to prepare and follow a manual of written procedures for "conducting normal operations and maintenance activities and handling abnormal operations and emergencies."). For that reason, the Presiding Officer should dismiss (or PHMSA should withdraw) this alleged violation. Such action would be consistent with past enforcement precedent. *See Exhibit 76, Final Order in re Rocky Mountain Pipeline System, LLC, CPF 5-2004-5001 (Dec. 11, 2006) p. 7* (withdrawing the alleged violation "because the regulation cited does not relate to the alleged problem.").

Even if the claim in Item 8 is allowed to stand although incorrectly pleaded, the record clearly shows that Respondent properly applied its integrity management procedures under TIARA. The TIARA model did not identify any threats or require any P&M measures.[13] Using this software, and in consideration of recommendations and analysis performed by the engineers familiar with the Pipeline, the Company implemented P&M measures, including scheduling of three emergency flow restrictive devices and the decision to run a TFI seam/crack tool.

As explained at the Hearing, the Company's TIARA analysis assesses threats on a forward-looking basis for the next five years based on information regarding the design, construction, operation and maintenance of the pipeline until the next reassessment. As such, part of the analysis would include the knowledge that a seam tool would be run during the next five year interval. The TIARA risk score for each threat is then examined and analyzed by the Company for sensitivity to varying inputs. Specific to the 2011 TIARA analysis and risk assessment on the Conway to Corsicana segment, Respondent included comments in the TIARA inputs and performed a hypothetical threat analysis to better understand the sensitivities of the TIARA software and identify the conditions under which the model would have identified a manufacturing threat. Even though the actual (as opposed to hypothetical) TIARA analysis did not identify any threats, based on the recommendations from its engineers, the Company nonetheless implemented additional P&M measures to protect the pipeline, expressly addressing sensitive areas and drinking water bodies along the Pegasus Pipeline.

Item 8 should either be dismissed or withdrawn because it fails to state a claim, and because it is based on an inaccurate reading of facts and application of the law.

[13] In compliance with the Company's TIARA procedures, the only notification provided to management was OIMS 2A Attachment #7 which conveyed the risk score. *Exhibit 60, Email from M. Weesner (Respondent) approving OIMS 2A Attachment #7 (Mar. 15, 2011).* No other management notifications or approvals were required under TIARA or OIMS 2A because there were no elevated threats.

D. NOPV Item 9

PHMSA alleges that Respondent failed to follow its own IMP procedures by not creating Management of Change (MOC) documentation when the decision was made to merge test segments for ILI purposes. Item 9 asserts a violation of 49 C.F.R. Parts 195.452(b)(5) and (j)(1). PHMSA goes on to assert that it is the failure to follow the MOC procedures that allowed the testable segments to be merged and resulted in a dilution of the TIARA risk scores. As clearly reflected in the record and further discussed at the Hearing, however, it is evident that Respondent did in fact create not one, but <u>two</u> MOC forms to support its decision, following a risk analysis conducted in 2005 that *specifically* considered the impact of the merger of testable segments on IMP ILI assessments. *Hearing Exhibits No. 10 and 11.*

Respondent's risk analysis in 2005 expressly considered the impact of the merger of testable segments on IMP ILI assessments. Respondent concluded that there would be <u>no</u> negative impact to the integrity risk assessment process. This analysis is reflected in the two MOC forms that Respondent produced to PHMSA, in compliance with the Company's OIMS procedure 7.2.[14] *Id.* As explained in the Hearing, under Respondent's TIARA program, dynamic risk assessment threats cannot be aggregated or masked over multiple miles and, therefore, the length of a testable segment simply does not impact the identification of threats. *See Transcript, p. 69, line 23 – p. 70, line 12.* Accordingly, PHMSA's NOPV Item 9 as alleged should be withdrawn.[15]

IV. <u>The Proposed Penalty Should be Withdrawn, or Alternatively, Substantially Reduced</u>

As the Agency admitted during the Hearing, there is no strict liability under the PSA. *Transcript, p. 84, lines 21-23.* The occurrence of an incident is not by itself a basis for a violation or penalty. Because Respondent complied with all applicable rules, no penalty should apply. Even if violations are deemed to have occurred, the amount of penalty is not warranted and should be significantly reduced in compliance with the PSA.[16] NOPV Items 1 – 4 and 7 are so closely related for penalty purposes, by sharing the same elements of facts and law, that they constitute a "related series of violations" subject to the PSA statutory penalty maximum of $1 million in the aggregate. Further, all of the penalties proposed under the NOPV should be reduced in consideration of the required statutory mitigation factors.

[14] The overall risk for potential leaks was reduced by the removal of pig traps, which included removal of potential sources of leaks (redundant piping, valves, flanges, and fittings). As a result, the MOC form did not require a risk assessment. With respect to consideration of any impact to ILI report timing, those considerations are addressed by the Part 195 regulatory timeframe and ILI vendor contract specifications.

[15] Throughout the Hearing, much of the discussion regarding NOPV alleged violations went well beyond the allegations pleaded in the NOPV itself. The discussion surrounding NOPV Item 9 was no exception, a point acknowledged by PHMSA counsel. *Transcript, p. 74, lines 6-8.* The extraneous discussions have no bearing on the allegations pled by PHMSA and are therefore to be ignored in this proceeding.

[16] As noted by PHMSA counsel in the Hearing, the proposed penalty in the NOPV is an "initial … starting point," or a "cap" and adjustment of the penalty will be considered by taking into account mitigating points made at the Hearing. *Transcript, p. 150, lines 17 – p. 151, line 7.*

A. Items 1-4 and 7 are "Related" for Penalty Purposes

NOPV Items 1 – 4 and 7 are related because they rely on the same facts and law and should constitute a single violation subject to the statutory $1 million penalty maximum for "related series of violations." *49 U.S.C. § 60122(a)(1); 49 C.F.R. Part 190.223(a).* All of these alleged violations rely on the Agency's argument that Respondent failed to consider that the segment was susceptible to seam failure. Assessing five separate penalties that when combined exceed $1 million, based on the same facts and applicable law, contradicts the plain language of the PSA, the Agency's rules and the Agency's only guidance issued to date on the subject.

The PSA requires that "any related series of violations" occurring prior to January 3, 2012 must be capped at no more than $1 million. *49 U.S.C. § 60122(a)(1); 49 C.F.R. Part 190.223(a).* The only legislative history on point indicates that this phrase should be applied in regard to a single incident.[17] Further, the only relevant guidance articulated by the Agency to date states that a related series of violations should include the situation where the facts and law for multiple claims "are so closely related…that they are not separate and should be considered one violation." *Exhibit 77, Final Order in re: Colorado Interstate Gas Co., CPF 5-2008-1005 (Nov. 23, 2009).*

The facts and law underlying NOPV Items 1 – 4 and 7 are inextricably intertwined and stem from one underlying PHMSA allegation. But for the Agency's allegation that the Respondent failed to conclude that the pipe segment was susceptible to seam failure, there would not be a basis for the purported violations asserted in Items 1 – 4 and 7. Item 1 addresses the alleged failure to conclude that the pipe was susceptible to seam failure. Item 2 builds on that allegation to assert that because Respondent did not make this conclusion, it exceeded the length of time allowed to run a seam ILI tool. In turn, Item 3 alleges that Respondent failed to complete a Management of Change form for extending the five year reassessment interval allegedly violated under Item 2. Similarly, Item 4 alleges again that because Respondent failed to conclude the pipe was susceptible to seam failure, it did not properly prioritize the timing of ILI seam tool runs. In Item 7 of the NOPV, PHMSA asserts that by not updating its risk assessment when the seam tool was delayed, the Respondent failed to follow certain internal procedures. This is further underscored by the Agency's PSVR, which cites the same evidence in support of these Items. *PHMSA PSVR, CPF 4-2013-5027, pp. 7, 13, 26* (describing the relevant evidence to include hydrostatic pressure test data and IMP assessment worksheet and risk assessments); and *pp. 19 and 45* (describing the relevant evidence to include IMP risk assessments, analyses and IMP Form 2.3).

[17] During reauthorization efforts that preceded the enactment of the Pipeline Safety Improvement Act of 2002, Senators had the following exchange regarding "related series of violations": [Sen. Hollings]: "*I am seeking clarification that all information requests issued by the Secretary pursuant to a single incident investigation are considered "related" for purposes of calculating the $1,000,000 civil penalty cap for a 'related series of violations'…" [Sen. Kerry]: "it is the intention of this legislation to treat all information requests pursuant to a single incident investigation as 'related' for purposes of applying the civil penalty cap…*" *Exhibit 81*, Senator Hollings (SC) and Senator Kerry (MA). "Pipeline Safety Improvement Act." Congressional Record 146:103 (Sept. 7, 2000), p. S8235.

B. Any Penalty Must Consider All Mitigating Factors

In addition to the above, the proposed penalty fails to account for relevant statutory mitigation factors required under the Pipeline Safety Act, including good faith and cooperation. *49 U.S.C. § 60122(b); 49 C.F.R. Part 190.225*. In assessing a penalty, the Agency must ("shall") consider the nature of the violation, circumstances, gravity, culpability and good faith in attempting to achieve compliance. *Id.* The Agency's PSVR failed to appropriately apply these factors, however, despite evidence in the record demonstrating that Respondent clearly complied with applicable regulatory requirements under IMP and did not at any time make conscious decisions to disregard the law.

In addition, the proposed penalty does not appear to consider the fact that Respondent was prompt, diligent and thorough in responding to and investigating the incident. The Agency acknowledges this fact in the PSVR. *Exhibit B to PHMSA PSVR, CPF 4-2013-5027 (Accident Report), pp. 11, 14* (noting that Respondent's response to the incident was timely, appropriate and in accordance with its procedures). To date, Respondent has spent over $75 million in response to the Mayflower incident and continues to review and revise its procedures in consideration of its incident investigation.

Finally, the proposed penalty should be reduced because PHMSA failed to expressly allege multi-day or statutory maximum claims in the NOPV in violation of due process and procedural requirements of the Administrative Procedure Act (APA). The APA requires that respondents in any enforcement proceeding be informed of the "matters of fact and law asserted." *5 U.S.C. 554(b).* This should include a clear statement of the theory on which the agency will proceed with its case, such that respondent can understand the issues and is afforded full opportunity to present its defense at a hearing. *Yellow Freight System v. Martin, 954 F.2d 353, 357 (6th Cir. 1992).* PHMSA's NOPV fails to satisfy these basic requirements because it does not provide any explanation of how the penalty was derived, including whether it alleges multi-day or statutory maximum claims. The proposed penalty should be reduced accordingly, as a matter of equity, policy, and in light of due process considerations.

For all of the reasons noted above, the proposed penalty should be significantly reduced.

V. The Compliance Order is Overbroad and Unnecessary

The Proposed Compliance Order (PCO) should be withdrawn because Respondent complied with the IMP regulations, thus there is no basis for a finding of violation that would allow issues of a PCO. In addition, the PCO is both overbroad and unnecessary and, as such, constitutes an abuse of agency discretion.

The PCO directs Respondent to undertake activities on "all assets," not just the Pegasus Pipeline. There is no authority under the PSA or the Agency's rules to apply incident-specific corrective actions in a NOPV to other company assets.[18] In addition, established federal case law requires

[18] At the Hearing, PHMSA incorrectly estimated that 80% of ExxonMobil Pipeline Company and Mobil Pipeline Company assets are pre-1970 ERW. *Transcript, p. 154, lines 14-15*. In actuality, the companies own or operate pipelines consisting of roughly 50% of LF-ERW pipe.

that injunctive relief be narrowly tailored to the specific harm alleged (not potential harm) and that an overboard scope of injunctive relief is an abuse of discretion. *Ahearn ex rel. N.L.R.B. v. Remington Lodging & Hospitality, 842 F.Supp.2d 1186, 1205-06 (D. Alaska 2012) (appeal dismissed Apr. 6, 2012) citing Stormans, Inc. v. Selecky, 586 F.3d 1109, 1140 (9th Cir. 2009).* Yet, the PCO does just that. *PCO, Paragraph 1* (requiring review and revision of the Company's IMP Plan for "all pre-70 ERW pipe *on any assets covered by the operator's IMP*") (emphasis added).

In addition, the PCO is unnecessary. The IMP regulations require continual evaluation of risk to a pipeline's integrity, regardless of whether incidents have occurred or violations are alleged. *49 C.F.R. Part 195.452(j)*. For this reason, and as a prudent operator, Respondent has already begun work on virtually all actions addressed in the PCO and expects to address all of the elements of the PCO.[19]

In light of the above, the PCO should be withdrawn or, at a minimum, modified to tailor the corrective actions to the assets at issue.

VI. Summary and Request for Relief

PHMSA closely audited the Pegasus Pipeline in 2007, including a specific and intensive review of Respondent's seam failure engineering analyses. Despite four PHMSA inspectors spending a full week on the review, the Agency did not find *any* flaws in the Respondent's IMP plan or implementation of its LF-ERW seam risk process. Even after the 2013 incident, the nation's leading experts in LF-ERW threat analysis and pipeline risk management who submitted affidavits for this matter concluded the Mayflower incident was not capable of either prediction or reliable detection using existing technology and methods. The Agency's own most recent Battelle report on ERW pipe risk generally, commissioned by PHMSA at the repeated request of NTSB and issued *after* this incident, similarly concluded that technology is not yet capable of finding such unusual anomalies as that causing the Mayflower incident. That conclusion is in stark contrast to the NOPV's bold after the fact assertion that "*there was more than adequate information*" to conclude that a specific risk existed. The record reveals that the anomaly causing this incident was not capable of prediction or reliable detection by technology and methods of inspection used at the time in compliance with applicable law. Moreover, Respondent not only complied with applicable law in considering the risk of seam failure, it actually did *more* than what is legally required regarding consideration of the risk of LF-ERW seam failure.

The Agency has issued relatively little regulation or guidance over the years on how to consider or identify the risk of LF-ERW seam failure. Despite this lack of direction, Respondent clearly did have a written IMP Plan in place that carefully considered the risk of seam failure of its LF-ERW pipe, in compliance with the minimal legal requirements and PHMSA guidance available, and consistent with industry standards on this issue. In fact, Respondent reviewed the risk of seam failure numerous times, over many years, using dozens of in-house and consulting engineers to review the data, analyses and conclusions. Three separate hydrotests were

[19] In addition, the timeframes set forth in the PCO, including Paragraph 1, are both unreasonable and unworkable.

performed, along with three ILI runs (one being a seam/crack tool), and four separate seam failure engineering analyses.

The alleged violations in Items 1 – 4 and 7 of the NOPV are unsupported by the record in this case because they presume a failure to conduct a seam analysis, which is controverted by the facts. In addition, there are errors and inconsistencies in the NOPV which were not explained by the Agency in the Hearing. In light of such errors, Items 5, 6, 8 and 9 go unsupported by the evidence. Item 8 should also be dismissed for failure to state a claim, because it asserts a violation of the Agency's O&M program rules, but discusses facts related to the Agency's IMP rules.

Even if the alleged violations were proved, the amount of penalty proposed should be significantly reduced. Items 1 – 4 and 7 are a "related series of violations" for penalty purposes, meaning they should be combined to a single claim and then subject to the statutory penalty cap. The Agency also failed to apply mitigating factors required by the statute in proposing a penalty.

Finally, the PCO is both illegally overbroad, and unnecessary, in light of the fact that existing IMP regulations require such 'continual evaluation' of risk factors and analyses proposed in the Compliance Order.

For all of these reasons, and in consideration of other matters as justice may require, the NOPV (including the Proposed Civil Penalty and the Proposed Compliance Order), should be withdrawn in its entirety. In the alternative, the claims asserted should be revised, the penalty substantially reduced and the Compliance Order substantially modified.

Respectfully submitted,

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Date: July 25, 2014

Index of Attached Exhibits[20]

No.	Exhibit
57	EMPCo IMP Manual, Appendix K, Validation and Repair Process (2010)
58	EMPCo IMP Manual, Sections 2.3.5.4.2-4 (Safety-Related Condition Requirements) (2010)
59	EMPCo Email from C. Gorman to IMP team (Jan. 10, 2011)
60	EMPCo Email from M. Weesner approving OIMS 2A Attachment #7 (Mar. 15, 2011)
61	EMPCo Email from L. Lamons to J. Johnson (GE PII) (Nov. 29, 2012)
62	EMPCo Email from C. Gorman to R. Coryell (GE PII) (Dec. 3, 2012)
63	EMPCo Email from C. Gorman to B. Hagerman (GE PII) (Mar. 15, 2013)
64	GE PII Email from J. Johnson to P. Vocke (EMPCo) (Apr. 12, 2012)

[20] The Exhibit references set forth in this Index continue from the Hearing Exhibits referenced and included with Respondent's Pre-Hearing Brief and discussed at the Hearing.

Index of Exhibits Included by Reference[21]

No.	Exhibit
65	Battelle Institute, "Final Interim Report" on ERW Seam Failures (Sept. 20, 2012)
66	Battelle Final Summary Report on ERW Seam Failures (Oct. 23, 2013)
67	Battelle ERW Study, 12th Quarterly Report (May 31, 2014)
68	NTSB Accident Report (Carmichael, MS), NTSB/PAR-09/01 (Nov. 1, 2007)
69	NTSB Safety Recommendation to PHMSA (Oct. 27, 2009)
70	NTSB Letter to PHMSA (Dec. 29, 2010)
71	NTSB Letter to PHMSA (Oct. 19, 2011)
72	OPS Alert ALN-88-01 (Jan. 28, 1988)
73	OPS Alert ALN-89-01 (Mar. 8, 1989)
74	OPS Final Rule, 59 Fed. Reg. 29379 (June 7, 1994)
75	OPS Final Rule, 65 Fed. Reg. 75378 (Dec. 1, 2000)
76	PHMSA Final Order, In re Rocky Mountain Pipeline System, LLC, CPF 5-2004-5001 (Dec. 11, 2006)
77	PHMSA Final Order, In re: Colorado Interstate Gas Co., PHMSA CPF 5-2008-1005 (Nov. 23, 2009)
78	PHMSA Final Order, In re: ExxonMobil Pipeline Company, PHMSA CPF 4-2011-5016 (Jun. 27, 2013)
79	PHMSA Liquid IMP Frequently Asked Question (FAQ) 7.19
80	PHMSA Notice of Amendment, In re Cenex Pipeline Company, PHMSA CPF 5-2011-5018M (July 26, 2011)
81	"Pipeline Safety Improvement Act," Congressional Record 146:103 (testimony of Senator Hollings and Senator Kerry) (Sept. 7, 2000)

[21] These documents should be considered part of the record in this matter, but they have not been attached with this submission because they are publically available.